

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Company)	
)	Docket 04-0476
Proposed general increase in natural gas)	
rates (Tariffs filed June 25, 2004))	

**DRAFT ORDER
SUBMITTED BY ILLINOIS POWER COMPANY**

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DRAFT ORDER SUBMITTED BY ILLINOIS POWER COMPANY

By the Commission:

I. PROCEDURAL HISTORY

On June 25, 2004, Illinois Power Company ("Illinois Power", "AmerenIP" or "IP") filed its Ill. C. C. No. 32, 10th Revised Sheet No. 1, 2nd Revised Sheet No. 2, 6th Revised Sheet No. 3, 3rd Revised Sheet No. 4, 3rd Revised Sheet No. 5, Original Sheet No. 5.1, Original Sheet No. 5.2, Original Sheet No. 5.3, 3rd Revised Sheet No. 11, 3rd Revised Sheet No. 12, 3rd Revised Sheet No. 13, 4th Revised Sheet No. 14, 3rd Revised Sheet No. 15, 2nd Revised Sheet No. 15.1, 5th Revised Sheet No. 16, 5th Revised Sheet No. 17, 4th Revised Sheet No. 18, 5th Revised Sheet No. 19, 6th Revised Sheet No. 20, 6th Revised Sheet No. 21, 4th Revised Sheet No. 21.1, 5th Revised Sheet No. 21.2, 1st Revised Sheet No. 21.3, 3rd Revised Sheet No. 23, 4th Revised Sheet No. 29, 6th Revised Sheet No. 43, 4th Revised Sheet No. 46, 3rd Revised Sheet No. 47, 4th Revised Sheet No. 48, 2nd Revised Sheet No. 49, 2nd Revised Sheet No. 49.1 and Ill. C. C. No. 34, 2nd Revised Sheet No. 1, 1st Revised Sheet No. 2, 2nd Revised Sheet No. 3, 2nd Revised Sheet No. 4, 1st Revised Sheet No. 4.1, 1st Revised Sheet No. 5, 1st Revised Sheet No. 6, 1st Revised Sheet No. 7, 1st Revised Sheet No. 9, and 1st Revised Sheet No. 10, hereinafter referred to as "Filed Rate Schedule Sheets", in which it proposed a general increase in natural gas rates, to be effective August 9, 2004. The filing of the Filed Rate Schedule Sheets was accompanied by prepared testimony and other exhibits and schedules and work papers pursuant to 83 Illinois Administrative Code Part 285.

Notice of IP's filing was published in newspapers of general circulation throughout IP's gas service area in accordance with the requirements of Section 9-201(a) of the Public Utilities Act ("Act"), 220 ILCS 5/9-201(a), and the provisions of 83 Ill. Adm. Code 255. The Commission entered a Suspension Order on July 21, 2004, and a Resuspension Order on November 10, 2004.

By letter dated July 19, 2004, from the Administrative Law Judge ("ALJ") assigned to the proceeding, IP was notified of certain deficiencies in its filing of schedules and work papers in accordance with 83 Ill. Administrative Code Part 285, Standard Filing Requirements for Electric, Gas, Telephone, Water and Sewer Utilities in Filing for an Increase in Rates. The deficiency letter required IP to provide various

revised and additional schedules or an explanation as to why certain schedules need not be provided. Information responsive to the deficiency letter was timely provided by IP. There are no outstanding deficiencies and IP has complied with all other Standard Filing Requirements for gas utilities in connection with this proceeding.

Petitions to intervene were filed by A.E. Staley Manufacturing Company, Archer-Daniels-Midland Company, Caterpillar, Inc. and TeePak, LLC, as the Illinois Industrial Energy Consumers (collectively "IIEC"); the Attorney General on behalf of the People of the State of Illinois ("AG"); Business Energy Alliance and Resources, L.L.C. ("BEAR"); Constellation NewEnergy-Gas Division, LLC ("CNE-Gas"); the Citizens Utility Board ("CUB"); Central Illinois Public Service Company ("CIPS"); Central Illinois Light Company ("CILCO"); and Dynegy Inc. ("Dynegy"). All of the foregoing petitions to intervene were granted by the ALJ. Subsequently, CIPS and CILCO withdrew their interventions.

Pursuant to notice duly given in accordance with the Act and the rules and regulations of the Commission, a prehearing conference was held in this matter before a duly authorized ALJ of the Commission at its offices in Springfield, Illinois, on August 5, 2004. Ten days prior notice of the prehearing conference was provided by the Chief Clerk of the Commission to municipalities in IP's gas service area in accordance with the requirements of Section 10-108 of the Act (220 ILCS 5/10-108). Evidentiary hearings were held at the Commission's offices in Springfield on January 20 and 21, 2005. Appearances were entered at the prehearing conference or at one or more of the evidentiary hearings by counsel on behalf of IP, IIEC, AG, BEAR, CNE-Gas, CUB, CIPS, CILCO, Dynegy and the Staff of the Commission ("Staff"). On _____, 2005, the record was marked "Heard and Taken" by the ALJ.

The following witnesses submitted testimony on behalf of IP: Frank A. Starbody, Peggy E. Carter, Daniel L. Mortland, Kathleen C. McShane, Karen R. Althoff, Ronald D. Pate, Leonard M. Jones, Brian W. Blackburn, Patricia K. Spinner, Michael J. Adams, Dr. Ronald E. White, H. Gene Eagle, Kevin D. Shipp, Wayne G. Hood and Curtis D. Kempainen, W. Chris Olsen, Dottie R. Anderson, Timothy L. Hower, Charles Mannix, Robert C. Porter and Lee R. Nickloy.

The following witnesses submitted testimony on behalf of Staff: Scott A. Struck, Burma C. Jones, Bonita A. Pearce, Janis Freetly, Michael McNally, Peter Lazare, Eric Lounsberry, Charles C. S. Iannello and Dianna Hathhorn.

The following witnesses submitted testimony on behalf of intervenors: David J. Effron, on behalf of the AG and CUB; Lee Smith on behalf of BEAR; Juliana Claussen and Troy Monroe on behalf of CNE-Gas; Christopher C. Thomas on behalf of CUB; and John W. Mallinckrodt and Dr. Alan Rosenberg on behalf of IIEC.

On January 20, 2005, during the evidentiary hearings, Staff filed a document captioned "Stipulation Concerning Resolution of Certain Revenue Requirements Issues" that was entered into between IP and Staff (the "Stipulation"). The Stipulation states

that AmerenIP and Staff stipulate that certain then-outstanding revenue requirements issues shall be resolved as set forth in the Stipulation. The Stipulation covers the resolution of a number of rate base and operating expense issues and the issues of capital structure, cost rates for long-term debt, transitional funding trust notes and preferred stock, cost of common equity and overall rate of return. Taken in conjunction with the parties' acceptance at earlier stages of the proceeding of other proposed adjustments to rate base and operating revenues and expenses, resolution of issues in accordance with the Stipulation would resolve all revenue requirements issues in this proceeding with the exception of the Hillsboro Storage Field Base Gas Inventory and the Hillsboro Storage Field Used and Useful adjustment which are addressed in Sections III.B and III.C, respectively, of this Order. Appendix A to the Stipulation showed the development of the overall revenue requirement and base rate increase assuming Staff's positions on the two aforementioned Hillsboro Storage Field issues are adopted, and Appendix B to the Stipulation showed the development of the overall revenue requirement and base rate increase under the assumption that AmerenIP's positions on the aforementioned Hillsboro Storage Field issues are adopted.

In addition, on February 9, 2005, AmerenIP and Staff entered into and filed a "Stipulation Concerning Resolution of Certain Tariff and Rate Related Issues" (the "Tariff Stipulation"). The Tariff Stipulation addressed resolution of issues relating to IP's proposed Critical Day Imbalance Charge, the provision of advanced metering and communications equipment to Service Classification ("SC") 76 customers and the offering of this equipment to other non-residential customers on an optional basis, the fees and charges to be assessed by IP for the Electronic Metering Index and for the advanced communications equipment, including an exit fee to be charged to customers electing the optional service but then dropping it less than six years thereafter, and certain related tariff language. All of the matters addressed in the Tariff Stipulation are discussed more fully later in this Order.

Both the Stipulation and the Tariff Stipulation state that AmerenIP and Staff acknowledge that each of the stipulated resolutions of issues listed in the Stipulation and the Tariff Stipulation (the "Stipulated Resolutions") is supported by the record in this docket but that based on the record, the Commission could have reached a different determination for each of the Stipulated Resolutions. The Stipulation and the Tariff Stipulation further state that AmerenIP and Staff each acknowledges that it is accepting the Stipulated Resolutions for purposes of this docket in order to reduce and simplify the issues in this proceeding, conserve resources, and reduce uncertainty. The Stipulation and the Tariff Stipulation each state that, accordingly, AmerenIP and Staff stipulate that neither of them will treat any of the Stipulated Resolutions as precedential for future cases, and that neither of them will argue, in any future cases, that the same or a similar issue to any of the Stipulated Resolutions should be decided by the Commission in the same manner set forth in the Stipulation or the Tariff Stipulation on the grounds that the issue was resolved in such manner in this docket or that AmerenIP or Staff agreed to such resolution in this docket. The Stipulation and the Tariff Stipulation further state that AmerenIP and Staff stipulate that they will request that the Commission's Order in this docket contain a statement that none of the Stipulated Resolutions shall be

considered precedential for future cases. Finally, the Stipulation and the Tariff Stipulation each state that it shall not preclude AmerenIP, Staff or any other party from arguing in a future case that the same or a similar issue to any of the Stipulated Resolutions should be resolved in the same manner as set forth in the Stipulation or the Tariff Stipulation, on any grounds other than that it was resolved in such manner in this docket or that AmerenIP or Staff agreed to such resolution in this docket.

At the hearing held on January 20, 2005, in this docket, the ALJ inquired on the record if any party had any objection to the Stipulation. No party stated that it had any objection to the Stipulation. (Tr. 37-38) Additionally, subsequent to the filing of the Tariff Stipulation by AmerenIP and Staff, no other party indicated any objection to the Tariff Stipulation.

The Commission accepts the Stipulated Resolutions as set forth in the Stipulation and in Appendices A and B thereto, and, as shown in further detail in Sections III.A, V.A and VI of this Order, below, has incorporated the Stipulated Resolutions into the determination of the overall gas utility revenue requirement for AmerenIP in this proceeding. Similarly, the Commission accepts the Stipulated Resolutions as set forth in the Tariff Stipulation and, as shown in Section VIII.B of this Order, below, has incorporated the Stipulated Resolutions set forth in the Tariff Stipulation into the determination of various tariff issues in this proceeding. None of the Stipulated Resolutions in either the Stipulation or the Tariff Stipulation shall be considered precedential for future cases; however, this shall not preclude AmerenIP, Staff or any other party from arguing in a future case that the same or a similar issue to any of the Stipulated Resolutions should be resolved in the same manner as set forth in the Stipulation or the Tariff Stipulation, on any grounds other than that the issue was resolved in such manner in this docket or that AmerenIP or Staff agreed to such resolution in this docket. In the discussion of Uncontested Adjustments to rate base, operating revenues and expenses and cost of capital and rate of return in Sections III.A, V.A and VI, below, this Order identifies each such adjustment that is a Stipulated Resolution. Similarly, in the discussion of transportation-related issues in Section VIII.B of this Order, the Commission identifies each resolved issue that is a Stipulated Resolution from the Tariff Stipulation.

The Commission notes that on September 30, 2004, during the course of this proceeding, IP was acquired by Ameren Corporation ("Ameren"). IP was formerly owned by Dynegy. The acquisition of IP by Ameren was approved by the Commission in Docket 04-0294 (Order issued September 22, 2004). Certain of the adjustments to rate base, operating expenses and cost of capital adopted for purposes of this proceeding, and the resolution of certain other issues herein, are the result of or otherwise reflect the acquisition of IP by Ameren from Dynegy.

Initial briefs were filed by IP, Staff, CUB, Dynegy, IIEC and BEAR. Reply briefs were filed by IP, Staff, Dynegy, IIEC and BEAR. An ALJ's proposed order was served on the parties. Briefs on exceptions were filed by _____, and briefs

in reply to exceptions were filed by _____. All exceptions and replies to exceptions have been duly considered by the Commission.

II. TEST YEAR

For the test year in this proceeding, IP selected a historical test year consisting of the 2003 calendar year ended December 31, 2003, with pro forma adjustments. No party objected to the test year selected by IP. The pro forma adjustments adopted for purposes of this proceeding are identified in Sections III, V and VI of this Order.

III. RATE BASE

Illinois Power's proposed rate base, as presented in its direct case filing, included both original cost less accumulated depreciation of gas utility plant in service at December 31, 2003, and original cost less accumulated depreciation of general and intangible plant allocated to the gas utility pursuant to an asset separation study performed by IP witness Adams of Navigant Consulting. IP's proposed rate base also included a number of adjustments to actual per-books balances at December 31, 2003. Some of these adjustments were objected to by other parties while a number of these adjustments were not objected to by other parties. Additional adjustments to rate base were proposed by Staff and/or the AG and CUB ("AG/CUB") and were accepted by IP. During the course of the case, certain of the proposed adjustments to rate base were modified based on updated information. Finally, as discussed in Section I of this Order, above, IP and Staff stipulated to the resolution of certain proposed adjustments to rate base as set forth in the Stipulation, and no other party objected to these Stipulated Resolutions. The uncontested or agreed adjustments to rate base that are being adopted for purposes of this Order are discussed in Section III.A below. The two remaining contested rate base issues, relating to the Hillsboro Storage Field Base Gas Inventory and the Hillsboro Storage Field Used and Useful status, are addressed in Sections III.B and III.C below.

A. Uncontested Adjustments to Rate Base

1. Depreciation Reserve Attributable to Contributions in Aid of Construction

The rate base incorporates the reserve for depreciation attributable to contributions in aid of construction that were recorded prior to 1984, at which time the Commission revised the Uniform System of Accounts ("USOA") to transfer the balance in Account 271, Contributions in Aid of Construction, to Account 101, Utility plant in service. (IP Ex. 2.1, p. 7)

2. Materials and Supplies and Working Gas Inventory

The rate base includes the 13-month averages for the test year of materials and supplies in Accounts 154 and 163 reduced by the 13-month average of accounts

payable balances associated with materials and supplies inventories recorded in Account 232. The rate base also includes the 13-month averages of working gas inventory balances in Account 164.1 and gas in leased storage in Account 165. As recommended by Staff witness Burma Jones, the 13-month average for Account 165 reflects a reduction of \$8,830,000 to rate base due to the removal of prepayments for purchased gas from the monthly balances used to calculate the 13-month average. (IP Ex. 2.36, p. 1, col. (C)) Additionally, as recommended by Staff witness Eric Lounsberry, the December 31, 2003 balance of gas in leased storage has been reduced by \$3,071,000 due to a reduction in IP's leased storage service contract with Mississippi River Transmission Corporation. (IP Ex. 2.36, p. 1, col. (F))

3. Cash Working Capital

The rate base includes a cash working capital component that is based on a lead lag study prepared by IP witness Adams of Navigant Consulting based on test year 2003 data. The study originally prepared by Mr. Adams, as summarized in IP Exhibit 10.7, was subsequently adjusted (i) to remove the impacts of prepayments for gas purchases (Staff Ex. 9.0, Sch. 9.02), (ii) to remove the cash working capital requirement associated with deferred income taxes and investment tax credits, in connection with removal of ADIT and ADITC from the revenue requirement computation, and (iii) to correct certain computational errors. The final cash working capital component reducing rate base by approximately \$1,073,000, was summarized on IP Exhibit 10.11.

4. Accumulated Deferred Income Taxes and Unamortized Investment Tax Credits

In connection with the acquisition of IP by Ameren, all of IP's accumulated deferred income taxes ("ADIT") and accumulated deferred investment tax credits ("ADITC") were eliminated as of September 30, 2004. Therefore, as of September 30, 2004, IP's balances of ADIT and ADITC were zero. Mr. Charles Mannix, Manager of Income Taxes for Ameren Services Company, testified that as a result, the rates to be set in this proceeding cannot be based on or reflect a reduction of rate base for any ADIT or ADITC that were recorded on IP's books as of and prior to September 30, 2004, or else IP would be in violation of the normalization provisions of the Internal Revenue Code, with the result that IP would no longer be entitled to claim accelerated depreciation for federal income tax purposes with respect to any depreciable assets subject to the jurisdiction of this Commission. (IP Ex. 18.1) The Stipulation provided that all ADIT at September 30, 2004, would be removed from the computation of rate base as presented by AmerenIP in IP Exhibit 2.55. In accordance with this Stipulated Resolution, all ADIT and ADITC recorded on IP's books as of and prior to September 30, 2004, have been removed in the computation of rate base for purposes of this case.

5. Customer Deposits

The rate base is reduced by the balance of customer deposits held by IP. IP originally used the December 31, 2003 balance of customer deposits for this purpose

but subsequently agreed to use the average of 13 monthly balances for the test year as proposed by Staff witness Hathhorn. (IP Ex. 2.1, p. 9 and IP Ex. 2.36, p. 1, col. (E))

6. Customer Advances for Construction

The rate base reflects the balance of customer advances for construction recorded by IP at December 31, 2003. (IP Ex. 2.1, p. 9)

7. 2004 Capital Additions and Accumulated Depreciation on Additions

IP proposed to include capital additions to gas utility plant during 2004 in rate base. IP witness Pate described IP's Asset Management process for identifying, prioritizing and tracking progress associated with making capital investments (IP Ex. 6.1). Mr. Pate and IP rebuttal witness Eagle presented exhibits detailing IP's gas utility capital projects for 2004, the status of those projects and the expenditures on each project at several points in time. Based on application of the known and measurable standard required of pro forma adjustments by 83 Ill. Adm. Code 287.40, Staff witness Burma Jones recommended that the Commission should include in rate base only 2004 capital additions projects that had reached "scheduled" status in IP's Asset Management process by a specified date. IP agreed with this approach. In the Stipulation, Staff and IP stipulated that rate base should include the costs of 2004 capital additions projects that had reached "scheduled" status as of September 30, 2004, as presented in IP's rebuttal filing. (IP Ex. 12.4 and IP Ex. 2.36, p. 2, col. (K)) In addition, rate base is reduced by the amount of accumulated depreciation recorded for these 2004 capital additions, using the assumption that the capital additions are placed in service ratably throughout 2004. (IP Ex. 2.40 and IP Ex. 2.36, p. 2, col. (L))

8. Accumulated Depreciation on Embedded Plant in Service

In connection with inclusion of 2004 capital additions in rate base, IP agreed that rate base should also incorporate accumulated depreciation during 2004 on utility plant in service at the end of the test year, December 31, 2003 ("embedded plant in service") as proposed by AG/CUB witness Efron and Staff witness Jones. In the Stipulation, IP and Staff stipulated that rate base should reflect accumulated depreciation on embedded plant in service through September 30, 2004, as presented in IP's rebuttal testimony. (IP Ex. 2.37 and IP Ex. 2.36, p. 1, col. (H))

9. Hillsboro Storage Well Adjustment

During the course of this proceeding, IP determined that the cost recorded for drilling a new well at the Hillsboro Storage Field included certain expenditures that were capitalized but should have been expensed. Accordingly, IP adjusted rate base to reduce gas plant in service and accumulated depreciation to reflect the removal of these expenditures from plant in service. (IP Ex. 2.42 and IP Ex. 2.36, p. 2, col. (M))

10. Completed CWIP Not Transferred to Plant in Service at December 31, 2003

The rate base includes balances recorded on IP's books at December 31, 2003, as construction work in progress ("CWIP") for projects that had been completed and placed in service as of that date but which had not been transferred to utility plant in service accounts as of December 31, 2003. This adjustment also incorporates certain miscellaneous charges recorded for these projects subsequent to December 31, 2003. In addition, IP reduced rate base to reflect the retirement of various gas plant assets in connection with placing the CWIP projects into service. (IP Ex. 2.5; IP Ex. 6.7; IP Ex. 2.36, p. 3, col. (Q)) Finally, IP reduced rate base to reflect accumulated depreciation on these projects. (IP Ex. 2.40 and IP Ex. 2.36, p. 2, col. (P))

11. Small CWIP Projects

The rate base includes the balance at December 31, 2003, associated with small CWIP projects with durations of less than one month, on which no Allowance for Funds Used During Construction is charged. In addition, IP reduced rate base to reflect the retirement of gas plant assets in connection with placing the small CWIP projects into service. (IP Ex. 2.6 and IP Ex. 2.36, p. 3, col. (R)) Finally, IP reduced rate base to reflect accumulated depreciation on these small CWIP projects. (IP Ex. 2.40 and IP Ex. 2.36, p. 2, col. (P))

12. Adjustment for Capitalized Pension Expense

IP's adjustments to test year operating expenses included an adjustment for higher pension costs, as discussed in Section V.A of this Order. AG/CUB witness Effron noted that a portion of this adjustment to pension expense should be capitalized. IP agreed that a portion of the pension expense adjustment it initially proposed should be capitalized, and therefore that rate base should be correspondingly adjusted. In the Stipulation, IP and Staff stipulated that a 30% capitalization factor should be applied to the pension cost adjustment, as proposed by AG/CUB witness Effron and Staff witness Bonita Pearce.

13. Advanced Metering Equipment

As discussed in Section VIII.B of this Order, IP agreed to recommendations by Staff, IIEC and CNE-Gas that IP provide to transportation customers more timely information on daily gas deliveries, and to this end indicated that it would install additional metering and telecommunications equipment to facilitate providing daily usage information. AmerenIP witness Althoff presented IP Exhibit 5.9 showing a projected investment of \$826,000 for this equipment. No party objected to the inclusion of this investment in rate base. (IP Ex. 2.36, p. 2, col. (O))

14. Retirement of River Bend Facility

IP reduced rate base to reflect the retirement in 2004 of its River Bend facility, which was still in service on December 31, 2003. This adjustment affected both utility plant in service and accumulated provision for depreciation. (IP Ex. 2.9 and IP Ex. 2.36, p. 3, col. (S))

15. Retirement of Computer Equipment

IP adjusted rate base to reflect the retirement in 2003 of certain mainframe computing equipment which was not recorded until 2004. This adjustment affects the portion of the original cost of this equipment and the related accumulated provision for depreciation that was allocated to the gas utility in the asset separation study. (IP Ex. 2.11 and IP Ex. 2.36, p. 3, col. (U))

16. Adjustment to General Plant Depreciation Reserve for Retirements

IP adjusted rate base component for the accumulated provision for depreciation for general plant to reflect the impact of retirements of certain general plant assets prior to December 31, 2003, that had not yet been recorded on IP's books as of that date. (IP Ex. 2.12 and IP Ex. 2.36, p. 3, col. (V))

17. Incentive Compensation Costs and Stock Options Costs Capitalized

In the Stipulation, IP and Staff stipulated that incentive compensation costs (including the related payroll taxes (FICA)) and costs for employee stock options incurred during 2003 should be excluded from the computation of the revenue requirement. Because a portion of these costs were charged to construction and therefore capitalized, the adjustments to remove these costs reduce rate base as well.

18. Relocation Reimbursements

Staff witness Burma Jones disagreed with IP's accounting for payments that are received from governmental entities or other third parties as reimbursement when IP retires facilities and replaces or relocates them at the request of the governmental entity or third party to accommodate a project, such as construction of a highway. IP's practice has been to record such payments as a credit to Account 108, Accumulated Reserve for Depreciation of Utility Plant and to record the cost of the replacement facilities in Account 101, Utility Plant in Service. Staff witness Jones testified that relocation reimbursements are Contributions in Aid of Construction ("CIAC") and should be recorded in the manner prescribed by Gas Plant Instruction 2(D) of the Uniform System of Accounts, which requires that contributions be credited to the accounts charged with the cost of construction. Although IP witness Peggy Carter, in rebuttal, disagreed with Ms. Jones and defended IP's accounting for relocation reimbursements, she also proposed a compromise approach whereby the third-party reimbursement payment would be recorded as a credit to Account 108 up to the actual cost recorded

for removal or retirement of the facilities being relocated, with the balance recorded as CIAC. Only the cost incurred for the replacement facilities in excess of the CIAC would be recorded as an addition to plant in service. In her rebuttal testimony, Staff witness Jones testified that this compromise approach would be acceptable. In the Stipulation, Staff and AmerenIP stipulated that the adjustment, and IP's future accounting for, relocation reimbursements would be based on this compromise approach. This adjustment impacts both plant in service and accumulated depreciation.

B. Hillsboro Storage Field Base Gas Inventory

1. Staff's Position

2. AmerenIP's Position

a. Hillsboro Injection Metering Error

Illinois Power stated that the issues relating to the Hillsboro Storage Field base gas inventory and to the Hillsboro used and useful status (addressed in Section II.C of this Order) have a common basis, namely, an injection metering error that occurred at Hillsboro over the period 1993 through 1999. (IP Init. Br., p. 4) The injection metering error resulted in depletion of the Hillsboro base and working gas inventory which was the cause of the declines in Hillsboro deliverability. IP provided a summary of the history of the Hillsboro injection metering error and IP's efforts to identify and resolve the causes of the Hillsboro deliverability declines. (IP Init. Br., pp. 6-10)

IP has had a storage field at Hillsboro since 1972; however, the Field was substantially upgraded in the early 1990s. As a result of the upgrade, which was completed in 1993, the peak day deliverability of the Hillsboro Field was increased to 125,000 mcf/day and the expected working gas volume of the Field was increased to 7.6 bcf. Injections into the Field in connection with the upgrade increased the total inventory in the Field to 21.7 bcf, consisting of 14.1 bcf cushion gas and 7.6 bcf working gas. (Rev. IP Ex. 14.1, p. 4) The expanded Hillsboro Field initially performed as expected. For the 1993-1994 through 1996-1997 heating seasons, the Field tested at a peak day deliverability value at or above 125,000 mcf/day in each season. Further, in the 1993-1994 winter, approximately 7.6 bcf of working gas was cycled (i.e., withdrawn for delivery to customers) from the Field. In subsequent winters, however, the amounts of working gas cycled from Hillsboro declined. Based on several years of declining annual deliverability, IP first observed that there could be a potential problem with the Hillsboro Field following the 1995-1996 winter withdrawal season. (*Id.*, p. 5)

IP states that during the ensuing several years, it devoted considerable effort, resources and attention to attempting to determine the source of the declining deliverability at the Hillsboro Field. IP initially investigated whether there was a reservoir problem, i.e., whether gas injected into the Field was migrating from the underground structure or whether the shape of the structure was different than had been expected, with the result in either case being that gas injected into the Field was

moving to areas where it could not be reached by the Field's withdrawal wells. IP had a vertical seismic profile and then a three-dimensional ("3-D") seismic profile of the Field prepared by outside consultants; these analyses resulted in the preliminary conclusion that approximately 3.5 bcf of gas had migrated to another underground structure to the northeast of the Hillsboro Field. (*Id.*, p. 7) Based on these results, in 2000 IP drilled a new well to the northeast of the Hillsboro Field where it was believed a sub-structure existed to which gas had migrated from the main reservoir. However, when the well was drilled, it was discovered that there was not a separate sub-structure in that area. (*Id.*, pp. 11-12) Thereafter, IP conducted a number of additional analyses to determine if there was a reservoir problem, including conducting crosswell seismic surveys¹; performing well stimulation treatments on a total of six of the wells at the Hillsboro Field²; performing additional neutron log analyses³; conducting flame ionization surveys⁴; analyzing whether gas leakage was occurring from plant piping or equipment back into the Field (none was discovered); and other analyses. These analyses continued into 2003. (*Id.*, pp. 12-15)

IP explained that while it was investigating whether there was a reservoir problem with the Hillsboro Field, it was also investigating whether there were problems with the injection and withdrawal metering at the Field.⁵ In August 1999, IP retained Peterson Engineering to conduct an audit of the metering at the Hillsboro Field. (Rev. IP Ex. 14.1, pp. 7-8) The Peterson audit identified two metering problems:

¹A crosswell seismic survey is a high resolution process capable of resolving underground features much smaller than those visible with a 3-D surface seismic analysis. (Rev. IP Ex. 14.1, p. 12)

²Well stimulation treatments consist of injecting chemicals through a well bore and into the reservoir to attempt to clean up barriers near the well bore that may be interfering with injections or withdrawals. (Rev. IP Ex. 14.1, p. 13)

³A neutron log is a survey done inside a gas well that can determine the water-gas mix within a reservoir by measuring the hydrogen ion concentration; this information was used in analyzing (i) whether there was gas leakage from the reservoir formation (none was detected) and (ii) whether the thickness of the "gas bubble" within the reservoir was changing (it was determined that the gas bubble in the Hillsboro reservoir was thinning). (Rev. IP Ex. 14.1, p. 14; IP Ex. 17.1, p. 8)

⁴Flame ionization tests are conducted at ground level to identify any migration of gas at the surface that would not be detected through neutron logs. No surface gas leakage was identified. (Rev. IP Ex. 14.1, p. 14)

⁵The metering at the Hillsboro Storage Field consists of (i) the plant metering, at which all gas coming into the Field for injection is measured, and (ii) injection and withdrawal metering at each of the 14 inject/withdraw wells located throughout the Field, at which gas is actually injected into the Field and subsequently withdrawn for delivery to customers.

- (1) Two new turbine injection meters installed at the Field were over-registering gas injections under certain operating conditions. When the compressors that were situated near the turbine meters were operating at 50% loadings, they caused the meters to over-spin, thereby recording a greater amount of gas than was in fact passing through the meters. The over-registration was determined to be 26% when the compressors were operating at 50% loadings. (When the compressors were operated at close to full loadings, however, only minimal over-registration occurred on the turbine meters.) (*Id.*, p. 8)
- (2) The orifice opening on the orifice meter at the south withdrawal secondary run was smaller than the value that had been stamped on the equipment at the manufacturer's plant.⁶ The orifice value stamped on the equipment was the same value that IP had ordered, but the size of the opening was actually smaller than the value stamped on the orifice plate. This meant that less gas was being withdrawn from the Field than had been believed, because the (incorrect) size of the orifice opening is a value that is input into the programmable logic controller for the meter, which calculates the value of gas passing through the meter. (*Id.*, pp. 8-9)

IP explained that to correct the turbine metering measurement errors, operating procedures were implemented to avoid the 25% and 50% compressor loading levels, since these were the compressor loading levels that caused the most significant over-registration on the turbine meters. Additionally, the static pressure sensing points for the turbine meters were relocated to improve their accuracy. These steps, which were recommended by Peterson Engineering, were implemented in May 2000. To correct the orifice metering problem, the correct, actual size of the orifice opening was input into the programmable logic controller so that it would correctly calculate the amount of gas passing through the meter. (*Id.*, pp. 10-11)

IP stated that the corrective actions taken in response to the Peterson Engineering audit largely mitigated the metering problems at the Hillsboro Field by the Spring of 2000; as a result, the actual injection measurement error occurred over the period 1994-1999. (Rev. IP Ex. 14.1, p. 16) IP stated, however, that at the time the corrective actions were taken it was believed that the injection metering error and the orifice withdrawal metering error were approximately offsetting. (*Id.*, pp. 9, 11) Moreover, for the 1999-2000 winter season, based on testing results as well as the overall accumulated experience of reduced deliverability from the Hillsboro Field over the preceding several years, IP had reduced the expected peak deliverability rating from

⁶The principal gas withdrawal facility into the south pipeline from the Hillsboro Field is the primary run. The secondary run, on which the orifice metering problem was found, only operates occasionally, during periods of high withdrawal flow rates. (Rev. IP Ex. 14.1, pp. 8-9)

125,000 mcf/day to 100,000 mcf/day.⁷ (*Id.*, pp. 18-19) Therefore, IP continued to investigate the source of the Hillsboro Field deliverability problem as described earlier.

A volumetric analysis of the volume of gas in the Field in the Spring of 2002 indicated that there was approximately 5.5 bcf less gas in the Field than there had been in the Spring of 1993.⁸ (*Id.*, pp. 15-16) This analysis, along with a comparison of the gas injected as measured by the plant injection meters (the turbine meters) to the gas being injected as measured by meters at the individual injection wells, led to the conclusion that the turbine meters had been recording substantially more gas than had actually been injected into the Field over an extended time period, and that as a result the gas volumes in the Field had been substantially depleted as a consequence of the measurement errors. Further, the other analyses that IP had conducted to attempt to determine if there was a reservoir problem with the Hillsboro Field enabled IP to rule out the likelihood that the source of the gas depletion was a structural or geological problem. (*Id.*, pp. 16-17)

b. IP's Adjustments to the Hillsboro Gas Inventory Amounts

IP stated that in 1999, based on the actual operating performance of the Hillsboro Field to that point, it made accounting entries to reflect the amount of gas believed to be in the Field at that time, based on then-available information. While the total amount of gas in the Field per IP's books was not changed, the total inventory was reallocated between working gas and base gas. Specifically, 3.6 bcf of gas with a book value of \$8,460,000 was shifted from the working gas account to the recoverable base gas account. This resulted in accounting balances of 17.7 bcf of non-recoverable and recoverable base gas and 4.0 bcf of working gas in the Field. Subsequently, based on its analysis completed in 2004 of the gas inventory depletion that had resulted from the injection metering error (described below), IP reversed the 1999 accounting entries. According to IP, the analysis completed in 2004 determined that there had been an inventory depletion of 5.8 bcf, of which 1.8 bcf was recoverable base gas and 4.0 bcf was working gas. In other words, 1.8 bcf had been withdrawn from recoverable base gas and supplied to customers as a result of the injection measurement error, and needed to be restored.⁹ IP stated that reinjection of the depleted 1.8 bcf of base gas

⁷The peak day deliverability rating of the Hillsboro Field has been subsequently restored to 125,000 mcf/day, prior to the 2003-2004 winter season. This deliverability has been confirmed by testing, and the peak day rating continues at 125,000 mcf/day for the 2004-2005 winter season. (Rev. IP Ex. 14.1, p. 19)

⁸The volumetric analysis uses data on the volume of the reservoir and gas-water saturation data from the neutron logs to develop an estimate of the gas volume actually in the reservoir. (Rev. IP Ex. 14.1, p. 15)

⁹IP witness Shipp testified that the cost of the base gas that had been withdrawn and supplied to customers is being recovered through the PGA beginning in 2004. (Rev. IP Ex. 13.1, p. 5)

has been completed. IP re-priced the base gas inventory to reflect the withdrawals and reinjection, resulting in a total value for the base gas inventory of \$31,044,200, which is \$10,367,838 higher than the base gas value recorded in 1993 of \$20,676,363.¹⁰ (Rev. IP Ex. 13.1, pp. 4-5) However, since the \$8,460,000 adjustment to base gas inventory recorded in 1999 was on IP's books and records at December 31, 2003, the amount of the pro forma rate base adjustment to test year balances proposed by IP is \$1,908,000 (i.e., \$10,368,000 minus \$8,460,000). (IP Ex. 2.1, p. 17)

Illinois Power opposed Staff witness Lounsberry's recommendation to disallow the \$10,367,838 adjustment to base gas inventory. IP argued that although Mr. Lounsberry did not dispute that the Hillsboro Field base gas inventory was depleted due to the metering error and needed to be replaced, he recommended that rate base incorporate only the 1993 base gas value, which IP argued is clearly obsolete and no longer representative of the value of the base gas in the Field. IP also argued that although Mr. Lounsberry stated several concerns about the methods IP used to estimate the Hillsboro inventory depletion, he offered no alternative calculation or estimate. IP emphasized that although it performed three analyses in determining the amount of the Hillsboro inventory depletion, the majority of Mr. Lounsberry's criticisms were directed at the study on which IP placed the least reliance. IP stated that the effect of Mr. Lounsberry's position is to assume that no base gas has been withdrawn and replaced. (Rev. IP Ex. 13.1, p. 5; IP Ex. 14.3, pp. 2-3) Finally, IP stated that Mr. Lounsberry's recommendation that IP should seek to recover through the PGA the value of the base gas that has been reinjected into the Field, even though the reinjected base gas is not gas that is to be withdrawn to supply to customers, is totally inappropriate and was not supported by any witness from the Commission's Accounting Department or Financial Analysis Division.

c. IP's Development of the Amount By Which the Hillsboro Gas Inventory Had Been Depleted

IP stated that it determined the depleted gas inventory volumes at Hillsboro using three separate methods. IP stated that two of those studies were performed by a qualified outside consultant under IP's direction, and the third was prepared internally. It is IP's position that the resulting estimate of the gas inventory depletion and reinjection is reasonable, reliable and sufficiently accurate to be the basis for a rate base component.

i. Reservoir Modeling

IP witness Timothy Hower, President of MHA, an international geology and engineering consulting firm, presented testimony describing the reservoir modeling and

¹⁰IP witness Carter explained that the repricing was based on the same method of monthly injection/withdrawal pricing used for working gas inventory: (i) withdrawals are priced at the average price of the storage field at the end of the previous month, and (ii) injections are priced at the average price of gas purchased during the month. (IP Ex. 2.1, p. 17)

volumetric analysis studies that his firm performed for IP as part of the overall determination of the Hillsboro gas inventory depletion. Mr. Hower holds B.S. and M.S. degrees in Petroleum and Natural Gas Engineering from Penn State University, and is a registered professional engineer in Colorado and Wyoming. He has been involved in the design, analysis and implementation of gas storage reservoirs for almost 15 years, and has a significant base of experience in Illinois working on gas storage reservoirs of several different companies. He is engaged in working on and managing reservoir studies on oil, gas and gas storage reservoirs worldwide. He has authored technical papers on gas storage and is co-author of an industry textbook entitled "Managing Water-Drive Gas Reservoirs", published by the Gas Research Institute. Mr. Hower has worked as a consultant for IP since 1992 and in that role has assisted IP with reservoir studies for both its Hillsboro and Shanghai Storage Fields. (IP Ex. 17.1, pp. 1-3)

Mr. Hower testified that the database of information available for the Hillsboro Storage Field, from which IP drew in conducting its reservoir modeling analysis (and its volumetric analysis, discussed below), is "one of the most comprehensive data sets that I have seen in my experience evaluating gas storage reservoirs." He stated that through the expenditure of substantial resources, IP has collected or commissioned 3-D seismic data, core data, special core analyses studies, neutron logs, detailed petrophysical and geological interpretations, a 3-D geological model, and a numerical reservoir simulation model for the Field. He testified that using this data, IP employed the most sophisticated analysis techniques available in estimating the volume of gas in place in the Hillsboro Field, and thus the amount of the inventory depletion. Mr. Hower stated that the techniques IP employed are state-of-the art techniques which adhere to standard, accepted industry practice for evaluating gas storage reservoirs and are used by gas storage operators throughout the world. These techniques are accepted by the Society of Petroleum Engineers ("SPE") and the Securities and Exchange Commission ("SEC"), who are responsible for outlining the standards used by the oil and gas industry in the assessment of hydrocarbon volumes, such as the amount of proved underground reserves. He stated that these same techniques are used by major publicly-held oil and gas companies in developing their estimates of reserves for purposes of public financial reporting. Mr. Hower stated that there is not a better, more reliable technique than what IP used to determine the gas volumes in place at the Hillsboro Field. (IP Ex. 17.1, pp. 5-6; IP Ex. 17.6, pp. 2-3)

Mr. Hower described the steps in the reservoir modeling analysis that was conducted to estimate the gas volumes in place at the Hillsboro Field:

- (1) A detailed 3-D geological model was constructed for the Hillsboro gas reservoir using 3-D seismic data and well logs from the injection and withdrawal wells at the Field.¹¹ The 3-D model contained an interpretation

¹¹Mr. Hower explained that acquisition and interpretation of 3-D seismic data involves measuring the travel time of a sound wave propagated through the sub-surface. The signal reflects off the various rock formations and bounces back to the surface where it is recorded. The structure of the reservoir is identified because the travel time of the

of the structure of the reservoir, specifically how it varies from point to point across the Field, as well as a description of the porosity, or available pore space, in the reservoir interval. (IP Ex. 17.1, pp. 7-8)

- (2) The 3-D model was used to construct a reservoir simulation model for the Hillsboro Field, including an interpretation of the structure and stratigraphy of the storage reservoir and caprock.¹² The model was calibrated, or matched, against observation well pressures, shut-in field pressures, gas saturation data from neutron logs performed in Fall 2003, and gas-water contact levels from the Fall 2003 neutron logs.¹³ (*Id.*, p. 10)
- (3) The reservoir simulation model was run using different injection rate schedules. Each case assumed a different volume of gas was injected over the time period in question (1994-1999) at Hillsboro. After each case was run, the results from the model (well pressures, field pressures, gas saturations and gas-water contact levels) were compared to actual field measurements. The case which provided the best match of simulation results to the actual measured data was the case that produced a total inventory volume in place of 16.8 bcf, or a variance (shortfall) of 5.8 bcf from the total inventory volume per IP's books. (*Id.*)

Mr. Hower explained that the reservoir simulation model approach is superior to the other two analyses conducted by IP because the reservoir modeling approach utilizes all of the available data (3-D seismic, core data and special core analyses, neutron logs, petrophysics and pressures) and provides a dynamic prediction of the reservoir's behavior over time. (*Id.*, p. 11) This latter point is relevant because the task at hand is to determine the volumes of gas actually injected into the reservoir over a multi-year period. The Hillsboro gas volume depletion of 5.8 bcf calculated using the reservoir modeling approach was equal to the final value that IP adopted after also taking into account the results of the other two analyses.

IP responded to various concerns expressed by Staff witness Lounsberry with respect to the use of the reservoir simulation model. First, Mr. Lounsberry asserted that "there is a limitation as to what the model can do" because the Hillsboro Field covers an

reflected signal from structurally high locations is shorter than in areas where the reservoir is deeper or farther below the surface. This process is conducted across the entire reservoir. The recorded data is processed to yield a 3-D image of the reservoir. (IP Ex. 17.1, p. 8)

¹²Mr. Hower explained that "stratigraphy" refers to the vertical sequence or vertical layering of rock formations in the sub-surface, and typically includes identifying different sub-surface beds of sandstones, shales, limestones and coals. (IP Ex. 17.1, p. 10)

¹³"Shut-in" refers to the status of the storage field or to individual wells when neither injections or withdrawals are occurring.

area of 8.2 square miles and has a total of 24 wells, from which data was used in the model, and that would not suggest using outputs from the model to make “concrete decisions” regarding rates. Mr. Hower responded that reservoir simulation is routinely used to evaluate hydrocarbon reservoirs that are much larger than the Hillsboro reservoir and contain significantly fewer wells. He reiterated that the reservoir simulation techniques adhere to the standards defined by the SPE and the SEC and are used by companies, financial institutions and countries as a basis for investing hundreds of millions of dollars. He stressed that these are the state-of-the art techniques, regardless of the ultimate use to be made of the volume estimate (e.g., setting utility rates or some other purpose). (IP Ex. 17.6, pp. 2-3, 5; IP Ex. 17.1, p. 13) He also explained that reservoir simulation models are effective specifically when used to evaluate gas storage reservoirs, including aquifer storage such as Hillsboro. He testified that reservoir simulation models are used throughout the industry to evaluate and optimize the performance of gas storage reservoirs and as a tool in realizing the full potential of underground storage fields in terms of volume and withdrawal rates, and in optimizing the design (including number of wells) and operation of underground storage facilities. (IP Ex. 17.1, pp. 13-14) Mr. Hower emphasized that reservoir simulation modeling is appropriate for use in connection with an aquifer storage reservoir such as Hillsboro where there is uncertainty as to the amount of gas that has been injected over time and the objective is to determine the volumes of gas in place in the reservoir (and thus the amount of the inventory depletion) in light of this uncertainty. (IP Ex. 17.6, pp. 3-5)

IP next responded to Staff witness Lounsberry’s argument that “the standards of the SPE and the SEC are not relevant for setting rates”, because although reservoir simulation models are used to meet government disclosure requirements or to produce reserve estimates used by investors in deciding whether to invest in a company, “the Commission is making ratemaking decisions for ratepayers who have no, or very little, choice about how IP manages its operations.” (Staff Init. Br., p. 16) IP stated that Mr. Lounsberry’s attempted distinction was invalid, and that there is no basis for his implication that the development of storage field inventory or reserve estimates for financial reporting and public company investor disclosure purposes is somehow less important than the development of such information for use in setting regulated rates. (IP Ex. 17.6, p. 3) IP pointed out that reserve estimates disclosed by oil and gas producing companies can be a very material part of investors’ evaluations of those companies and whether to make investments in their securities and at what price. IP also noted that most investors have no ability to “double-check” the reserve estimates published by such companies, so it is important to the integrity of the public capital markets that the most reliable techniques available, such as those used by IP in determining the Hillsboro gas volumes in place, be used. (*Id.*) IP stated that this is precisely why these same techniques are required by the SPE and the SEC for the preparation of reserve estimates that are published for financial reporting and disclosure purposes. IP observed that recent experience has shown that changes to reserve estimates, and damage to the credibility of the companies providing them, can have significant financial impacts in the capital markets and on unsuspecting investors, as well as potentially resulting in serious financial liabilities for the companies. (*Id.*) IP

concluded that there is no basis for Mr. Lounsberry's suggestion that reservoir modeling techniques are not good enough to use in setting rates. (IP Rep. Br., pp. 39-40) IP emphasized that in any event, the reservoir modeling techniques that Mr. Lounsberry suggested are not good enough for setting regulated rates are in fact the state-of-the-art techniques for determining the volumes of gas or oil in an underground reservoir. IP stated that whether the task at hand is determining the volume of proved reserves from a producing hydrocarbon asset or setting regulated rates, the objective is to determine the most accurate value possible. IP stated that there are no better techniques available for doing this than the reservoir modeling techniques IP used in determining the amount of gas in the Hillsboro Storage Field and thus the gas inventory depletion amount. (IP Ex. 17.6, pp. 2-3; IP Rep. Br., p. 40)

IP stated that Mr. Lounsberry's contention that reservoir simulation techniques are appropriate for "production reservoirs" but not for aquifer storage reservoirs such as Hillsboro which did not originally contain natural gas and for which the volume of gas injected into the reservoir should be known, was baseless. IP stated that in practice, for many aquifer gas storage reservoirs there are uncertainties and the gas volume in place is not accurately known. (Such uncertainties can arise, for example, from gas leaks in wells and surface facilities or gas losses in the subsurface (migration off structure), as well as gas measurement errors. (IP Ex. 17.6, p. 4)) This is the case at Hillsboro where the gas injection measurement error resulted in uncertainty with respect to the gas volume in place at the Field. IP stated that this is precisely why it is appropriate to use reservoir simulation techniques and methods like those used in the oil and gas production industry which face uncertainty as to the hydrocarbon volumes in place in a reservoir or production area. IP stated that since it is undisputed that there was uncertainty as to the gas volumes in place at Hillsboro, the appropriate techniques to use to obtain the most accurate evaluation of the gas in place possible are the same techniques routinely used by the petroleum industry for the same purposes, namely, reservoir simulation techniques. IP emphasized that the overriding point is that the approach used by IP to determine the gas volumes in place at Hillsboro employed state-of-the-art, industry accepted techniques that provide the best estimate possible given the uncertainty in the gas volumes in the reservoir, regardless of the type of reservoir involved. (IP Ex. 17.6, pp. 4-5; IP Rep. Br., pp. 40-41)

Finally, Mr. Lounsberry asserted that a reservoir model is dependant on historical information from the storage field but that there were problems with gas measurement data at Hillsboro starting in 1994, and that the reservoir model had only been matched to very recent (2003) field data. (Staff Ex. 7.0, pp. 18-19; Staff Ex. 17.0R, pp. 20-22) Mr. Hower responded that the Hillsboro simulation model was not developed using only 2003 field data. Rather, it was calibrated and matched against data collected over the entire life of the Field, from 1974 forward. He testified that the model was matched to all observation well pressures available for the entire life of the Field and to all shut-in field pressures available for the entire life of the Field. Data was used for periods in which Hillsboro operated at its full "design" capacity. The model was then run to simulate the operation of the Field during the historic periods when the measurement error occurred, in order to determine the historic injection schedule best matching the known, historic

field data. (IP Ex. 17.6, pp. 6-8) IP also emphasized that the Hillsboro reservoir simulation model was constructed on a foundation of known, accurate data such as 3-D seismic, core data, special core analyses, petrophysical calculations and measurements of well and field data. Mr. Hower emphasized that this was a highly sophisticated data base of information about the Hillsboro reservoir, and it consisted of known data. He explained that the only data item in question was the historic (1994-1999) gas injection volumes, and thus the reservoir model was used to solve for this data item, by performing numerous model runs using various assumed gas injection schedules over time, and selecting the run (and thus the historic gas injection schedule) that produced the best match with the known, measured field data. (IP Ex. 17.1, p. 14; IP Ex. 17.6, pp. 5-6) IP pointed out that Mr. Lounsberry's comments showed his fundamental lack of understanding of the reservoir modeling technique and how it was used by IP in determining the gas volumes in place at Hillsboro. IP explained that contrary to Mr. Lounsberry's misunderstanding of the facts, the reservoir simulation model for the Hillsboro Field was not used to make predictions about the reservoir's future behavior once it is refilled. Rather, the reservoir model was used to determine the volumes of gas in the Field in 2004, in a situation of depleted inventory, which was done by modeling the performance of the Field in past years using a substantial base of known data, not by projecting the Field's performance in future years. (IP Ex. 17.6, p. 7) Thus, IP explained, the historic data available for the period subsequent to 1993 (which is only a subset of the data used in developing the model, see IP Ex. 17.6, pp. 6-8) could be used in developing a reservoir model useful in determining the (reduced) volume of gas in place in 2004, before significant progress had been made in reinjecting gas to replace the depleted inventory. (IP Rep. Br., pp. 41-42)

IP concluded that the reservoir modeling approach used to determine the gas volumes in place in Hillsboro (and thus the amount of the inventory depletion) was relevant, robust and appropriate; it was based on a substantial quantity of known data covering the history of the Field; and it constituted a state-of-the-art, industry accepted technique that provided the best estimate possible of the gas volumes in the Field given the uncertainty as to the volumes injected over the 1994-1999 period. (IP Ex. 17.6, pp. 3-6) IP argued that Mr. Lounsberry's concerns fall far short of providing any reason to not rely on the Hillsboro inventory depletion value developed using the reservoir simulation model.

ii. Volumetric Analysis

Illinois Power explained that the second method it used, volumetric analysis, was conducted as follows:

- (1) As described above, a detailed 3-D geological model was constructed for the Hillsboro gas storage reservoir. (IP Ex. 17.1, pp. 7-8)
- (2) Neutron logs compiled in the Fall of 2003 were evaluated to determine the gas saturation and the location of the gas-water contact within the

reservoir interval. The location of the gas-water contact provides the base of the gas bubble in the reservoir.¹⁴ (*Id.*, p. 8)

- (3) With an interpretation of the top of the reservoir (from the 3-D geological model) and estimates of the base of the gas bubble and of the gas saturation within the bubble (from the neutron logs), the gas volume in place as of November 2003 could be calculated. (*Id.*, pp. 8-9)

IP stated that using this technique, the volume of gas in place at Hillsboro was calculated to be 14.2 bcf, which represented a shortfall of 8.4 bcf from the gas volumes indicated by accounting records based on the historic injection records. (*Id.*, p. 9) This was the smallest estimate of the gas volumes in place, and thus the largest estimate of the inventory depletion, developed by the three techniques that IP employed.

iii. Metering (Well Chart) Analysis

Illinois Power explained that the third approach it used to determine the Hillsboro inventory depletion was a comparison of injected volumes as measured by the plant turbine meters to injected volumes as measured by the injection meters at the 14 individual wells at the Field, during historic periods when the turbine measurement error was occurring. This comparison was conducted using data from the injection months in the years 1994, 1995, 1998 and 1999. IP stated that to conduct this analysis, data was needed from well chart logs taken from the injection metering at each of the 14 wells. The injection data from the well charts then needed to be integrated on a daily basis to develop a total injection volume for the day that could be compared to the volume injected as measured (incorrectly) on the plant turbine meters. IP witnesses Hood and Kemppainen testified that the well charts for 1994 and 1998 were sent to an outside chart integration service to be integrated using custody transfer computation processes, while the well charts for 1995 and 1999 were integrated by IP employees using an in-house chart integration program. Using the comparisons between the daily volumes recorded on the plant turbine metering and the daily volumes injected at the wells as determined from the integrated well charts, a percentage error (correction factor) for the injection volumes measured at the turbine meters was developed for each injection season. These percentage errors were: 1994, (22.1%); 1995, (7.0%); 1998, (12.7%); and 1999, (8.9)%. (Rev. IP Ex. 14.1, pp. 21-23; IP Ex. 14.2, pp. 3, 6-10)

IP stated that the results of the well chart analysis indicated annual adjustments to the Hillsboro gas inventory of 1.4 bcf to 5.8 bcf, with an average value from the two years for which the well charts were sent to an outside service for integration of 4.9 bcf. (IP Ex. 17.1, p. 7) IP also stated that the upper end of the range of the percentage

¹⁴As noted earlier, a neutron log performed at a well measures the hydrogen ion concentration of the fluids in the reservoir in the vicinity of the well bore. Mr. Hower explained that since the hydrogen ion concentrations of gas and water are different, this technique enables the operator to determine the water-gas mix in the reservoir. (IP Ex. 17.1, p. 8)

errors developed through this approach, (22.1)%, was consistent with the inventory shortfall value of 5.8 bcf developed by the reservoir simulation modeling. (Rev. IP Ex. 14.1, pp. 17-18; IP Ex. 14.2, p. 4) Further, IP stated that by November 2004, it had reinjected an additional 2.6 bcf of gas into the Hillsboro Field with no gas yet seen at the Field's two key observation wells. IP stated that these results confirmed that the turbine meter correction factors calculated for the two years for which IP performed the chart integration in-house, 1995 (-7.0%) and 1999 (-8.9%), were too low. (Rev. IP Ex. 14.1, pp. 24-25)

IP responded to concerns that Staff witness Lounsberry expressed about the well chart integration study. IP emphasized that of the three studies conducted, it placed the least reliance on the well chart integration study, and placed the greatest reliance on the results of the reservoir simulation modeling. (IP Ex. 14.3, p. 2) IP stated that if it had placed no reliance on the well chart analysis, its overall estimate of the Hillsboro gas inventory depletion would not have changed. IP used the results of the well chart integration study to place the overall estimate at the bottom end of this range, i.e., 5.8 bcf. (*Id.*, p. 11)

IP responded to Mr. Lounsberry's concern that IP should have used more days of chart data for 1994, 1995, 1998 and 1999, and should have had the well charts for 1995 and 1999 integrated by an outside vendor rather than in-house. IP stated that the number of days that could be used was limited by the number of days in each month for which IP had well charts available for all of the injection wells that had operated on that day. For some months there were as few as two days for which chart data for all wells was available, while for other months there were more than five days for which chart data for all wells was available. IP stated that overall, the well charts were integrated for virtually all the days in the 1994, 1995, 1998 and 1999 injection seasons for which IP had usable well chart data for all injection wells. Further, for 1994, the number of days of data that were used constituted 25% of the total number of days on which gas was injected into the Field. IP stated that the corresponding percentages for 1995, 1998 and 1999 were 15%, 19% and 15%, respectively. (IP Ex. 14.3, pp. 3-4)

With respect to Mr. Lounsberry's concern that the well charts for 1995 and 1999 were integrated by IP using an in-house program rather than by an outside chart integration service, IP acknowledged that the chart integration results using the in-house program may have been less accurate than the chart integration results produced by an outside service. (Rev. IP Ex. 14.1, pp. 22-23) However, IP stated that it placed greater reliance on the turbine metering correction factors calculated for the two years (1994 and 1998) for which the chart integration was performed by an outside service. IP also pointed out that subsequent experience in connection with re-filling the Field showed that the calculated correction factors for the two years for which the well charts were integrated in-house were too low. (*Id.*, pp. 24-25; IP Ex. 14.3, pp. 10-11)

IP also responded to Mr. Lounsberry's concern that the 1999 Peterson Engineering metering audit report had observed that the orifice meters at the individual wells were not set up according to AGA guidelines for orifice metering and that the

Peterson Engineering report that noted that “for well production gas metering, the metering measurements should not be used as an engineering basis due to the insufficient length of straight piping upstream of the orifice plates and a protrusion in the flow path.” IP pointed out that the Peterson report also stated that “the individual well metering was reasonably accurate when injecting gas, but not accurate for natural gas withdrawal”. IP stated that the well chart data it used for the chart integration analysis was injection data only, not withdrawal data. With respect to the Peterson report’s reference to the “well production” gas metering, IP stated that this is an industry term that refers to withdrawal from the ground; therefore, the statement Mr. Lounsberry cited was referring to the withdrawal metering attributes. IP pointed out that with respect to the injection metering at the wells, the Peterson report stated: “For injection, the meter runs are in general accordance with AGA Report #3, Part II for the installed orifice plates.” IP emphasized that in the well chart integration study, it used well chart injection metering data, not withdrawal metering data. (Rev. IP Ex. 14.1, pp. 21-22; IP Ex. 14.3, pp. 7-8) In response to Staff’s argument that the orifice meters were not set up in accordance with the requirements of 83 Ill. Adm. Code Part 500, IP pointed out that, as Staff itself admitted, the requirements of Code Part 500 for metering only apply to meters used to measure customer load, and that “Code Part 500 standards do not apply to utility storage fields” (Staff Init. Br., p. 45). (IP Rep. Br., p. 34)

Next, IP responded to Mr. Lounsberry’s concern that IP did not integrate well charts for the 1996-1997 injection seasons. IP stated that the analysis was not performed using data for 1996-1997 because the interstate pipelines had changed their definitions of the gas “day”, which determined the measurement day used to record injected volumes at the plant turbine meters, from “noon to noon” to “9 A.M. to 9 A.M.,” but the gas day start time on the individual well meters was not re-set to coincide with the revised gas day until 1998. (Rev. IP Ex. 14.1, p. 23) IP stated that to overcome this problem would have required that the well chart data be integrated on an hourly rather than a daily basis, which would have required considerably more time to complete, and would have required that IP have two consecutive days of well chart data for all of the wells to match against each day of turbine metering data. (IP Ex. 14.3, pp. 5-6)

IP responded to Staff’s criticism of the fact that when IP performed separate well chart analyses for 2000 and 2002 (after the turbine injection metering error had been remediated) to evaluate the accuracy of this method, the injection volumes as determined at the well meters varied from the injection volumes as measured on the turbine meters by (0.95)% for 2000 and (2.7)% for 2002. Specifically, Staff criticized the variance for 2000 of (2.7)% as too high because 83 Ill. Adm. Code 500.190 (applicable to customer load meters) “requires that a meter may not be more than 2% slow.” (Staff Init. Br., pp. 11-12) IP stated that this comparison based on Code Part 500 was baseless. IP noted that the 2% accuracy requirement specified in Code Part 500.190 is applicable to meters that are retested per the provisions of Code Parts 500.200 and 500.210, and it allows custody transfer meters to be reinstalled at customer premises without adjustment. IP stated that the testing of a meter under Code Part 500.200 requires suitable testing equipment and is performed at two rates of steady state flows. In other words, the 2% accuracy requirement of Code Part 500.200 is based on a test of a single meter against a fixed test device. In contrast, IP pointed out, the (2.7)%

difference between the injections measured on the Hillsboro turbine meters and on the well injection meters was based on a comparison of the measurements recorded by two different sets of operating meters. Each set of meters could have been operating within 2% accuracy per the requirements of Part 500.190 yet there could be a 2.7% difference (or larger) between their respective measurements. (IP Ex. 14.3, pp. 8-9; IP Rep. Br., pp. 34-35)

IP responded to Staff's concern that the well chart integrations for the confirmatory 2000 and 2002 analyses were performed using IP's in-house chart integration program, not by an outside chart integration service. IP acknowledged that it would expect its in-house program to be less accurate (in terms of chart integration, not actual measurements) than a chart integration performed by an outside service, but stated that this only makes the small variances between the injection well measurements and the turbine meter measurements in the 2000 and 2002 analyses more convincing in terms of showing that the well chart method is reliable. IP pointed out that Staff's comment was inconsistent with other Staff arguments, because Staff elsewhere complained about the fact that IP placed heaviest reliance on the chart integration results for 1994, which were performed by an outside integration service, rather than those for 1995 and 1999, which were performed using IP's in-house program. (IP Rep. Br. p. 35)

IP stated that Staff's comments that IP must have been concerned about what Staff characterized as a "continued error" because IP replaced the Hillsboro turbine injection meters in 2003 and 2004, was also inconsistent with other Staff arguments. IP pointed out that Staff elsewhere contended that IP has been in Staff's view "reactive rather than proactive when determining when to make upgrades or other improvements at its storage fields" (Staff Init. Br., p. 40), yet here Staff proffered a negative inference from the fact that IP replaced the turbine meters with newer-technology ultrasonic meters even though the turbine meters were not worn out. IP witnesses Hood and Kempainen explained that the turbine meters were replaced with the ultrasonic meters because (i) the ultrasonic meters require less maintenance than the turbine meters, thereby providing maintenance cost savings; (ii) replacement of the turbine meters eliminated the need for operating personnel to devote attention to operating the compressors at loadings that did not impact the turbine meter measurements; and (iii) the ultrasonic meters are a newer, more technologically advanced product which provides improved measurement. (IP Ex. 14.3, pp. 9-10) IP stated that the fact that a newer technology product, which was not available previously, performs better than an older technology product is unremarkable. (IP Rep. Br., p. 36)

IP also stated that Staff's emphasis on the fact that the ultrasonic meters provide improved measurement as compared to the turbine meters is irrelevant to the reliability and accuracy of the well chart analysis, which measured the amount of the 1993-1999 turbine metering error based on the difference between the injection volumes recorded by the turbine meters and the injection volumes measured by the metering at the individual injection wells. IP stated that Staff's comments about the 2000 and 2002 confirmatory analyses and the replacement of the turbine meters with ultrasonic meters

provided no useful information to the Commission on this issue. IP emphasized that the well chart analyses IP performed for 2000 and 2002, after the cause of the turbine injection metering error was remediated, showed that the integrated well chart metering data from the 14 individual injection wells can be used to accurately depict the amount of gas injected into the Hillsboro Field in a given time period. (IP Rep. Br., pp. 36-37)

Finally, IP responded to Mr. Lounsberry's contention that IP applied a consistent correction factor for all months that the measurement error occurred, and that the turbine measurement error would have fluctuated from month to month because it was a function of the operating rate of the Hillsboro compressors which he believed would not operate at the same average speed every month. IP stated that the stated premise of Mr. Lounsberry's concern was incorrect: IP witnesses Hood and Kemppainen explained that the three Hillsboro compressors are synchronous motor driven and operate at a constant speed. (Rev. IP Ex. 14.1, p. 25) They also stated that assuming that what Mr. Lounsberry really meant was that the compressors do not operate at constant loadings, his concern was still unfounded, because the compressor loadings are not a function of time. Rather, they are dependent on other factors such as suction pressure, outlet pressure, required hourly throughput, and the number of compressors on line, all of which can change on a daily basis. They concluded that using an annual correction factor (percentage error) representing an average of the daily data (which is what IP did) was appropriate. (*Id.*, p. 26; see also IP Ex. 14.2, pp. 3, 6-10) Mr. Hood and Mr. Kemppainen also testified that, because a given set of conditions affecting the compressor loadings was as likely to occur in 1994 as in 1999, the correction factor was independent of time. IP concluded that use of a constant correction factor from the well chart analysis was appropriate. (IP Ex. 14.3, pp. 11-12)

Illinois Power also emphasized that Mr. Lounsberry's final criticism concerning the "constant correction factor" is unfounded in the context of IP's overall development of the 5.8 bcf Hillsboro inventory depletion. IP stated that it did not use a single correction factor (percentage metering error) for the entire six-year period to develop an independent estimate of the injection shortfall, but rather used the well chart analysis to develop a range of correction factors (i.e., an average correction factor for each of four years), and also ran the reservoir simulation model iteratively against various correction factors to find the percentage injection metering error (i.e., the actual gas injection history) that best matched the reservoir data as generated by the model. IP explained that a gas injection history that reflected a 22% correction to the recorded injections per the turbine meters, which corresponded to the correction factor calculated by the well chart study for 1994, produced an in-place volume estimate of 16.8 bcf, and thus an inventory shortfall of 5.8 bcf, which best matched the actual reservoir characteristics as generated by the reservoir simulation model. (IP Ex. 17.1, pp. 11-12; IP Ex. 17.5, pp. 1-2; Rev. IP Ex. 14.1, pp. 17-18; IP Ex. 14.2, pp. 3-4; IP Ex. 14.3, p. 12)

IP also noted that as of November 2004, it had reinjected 2.6 bcf of gas into Hillsboro without any gas being seen at two key observation wells, Gregg No. 1 and Furness No. 1; and that it can be concluded from these facts that the (7.0)% and (8.9)% correction factors indicated by the 1995 and 1998 well chart analyses were lower than

the actual metering error. (Rev. IP Ex. 14.1, pp. 24-25) IP stated that with respect to the issue of whether IP's use of the (22.1)% correction factor for the entire period, because it best matched the estimate of gas in place in 2004 developed using the reservoir modeling analysis, was appropriate, or whether IP should have factored in the lower correction factors calculated for the other three years, if the turbine metering error had only been in the range of (7.0)% to (8.9)% (which means that the gas inventory depletion would have been less than 2.6 bcf), then by the time IP had reinjected 2.6 bcf of gas into the Hillsboro Field, it should have been seeing gas at these observation wells. However, since no gas has been observed at these wells despite the reinjection of 2.6 bcf, the four-year correction factor (turbine injection measurement error) must exceed (8.9)%. (IP Rep. Br., pp. 37-38)

iv. Development of IP's Overall Inventory Depletion Value

Illinois Power emphasized that it employed three independent approaches to develop an overall value of the Hillsboro gas inventory depletion that resulted from the turbine injection meter measurement error over the period 1993-1999. IP stated that the chart integration analysis measured gas volume by gas flow; the volumetric analysis measured gas volume based on a neutron log response to gas in the reservoir; and the reservoir simulation modeling measured volume by using sensitivity analysis to find an injection/withdrawal profile that matched the Hillsboro reservoir's pressure responses. (Rev. IP Ex. 14.1, p. 27) The well chart integration analysis produced a range of average annual correction factors (percentage error) to the recorded injection data of (7.0)% to (22.1)%. The volumetric analysis produced a value of gas in place of 14.2 bcf, indicating an inventory depletion of 8.4 bcf. The reservoir simulation modeling produced a value of gas in place of 16.8 bcf, which matched an average percentage injection measurement error over the six-year period of 22%, indicating an inventory depletion of 5.8 bcf. IP stated that the reservoir simulation technique, being recognized as superior to the other two techniques because it is a dynamic approach rather than a static approach, was given the primary weight. IP also stated that the well chart integration analyses, which produced correction factors much more consistent with the 5.8 bcf shortfall estimate than with the shortfall estimate produced by the volumetric analysis, helped to confirm that the value produced by the reservoir simulation modeling should be adopted. (Rev. IP Ex. 14.1, pp. 17-18; IP Ex. 14.3, p. 11; IP Ex. 17.1, p. 11)

Illinois Power responded to an additional, overall concern expressed by Staff witness Lounsberry, based on the fact that IP has indicated that it will engage in further study in the summer of 2005 to determine if further adjustments to the Hillsboro inventory are appropriate. IP stated that while the 2005 analysis, which will incorporate data collected in the course of operations during the 2004 injection season and 2004-2005 withdrawal season, as well as other ongoing analyses to be conducted in the normal course, could result in some fine tuning to the 5.8 bcf inventory shortfall estimate, it is not expected to be altered significantly. (Rev. IP Ex. 14.1, pp. 26-27) IP also pointed out that it is most likely that if the 5.8 bcf value is biased, it is biased to the low side, i.e., the most likely direction of any change in this value would be an increase.

(IP Ex. 14.3, pp. 12-13) IP stated that the fact that the 5.8 bcf inventory shortfall value could be revised in the future does not detract from the reasonableness of this value which IP has developed and presented in this case. (*Id.*, p. 12)

IP responded to Staff's contention that the adjustment to the Hillsboro base gas inventory should not be included in rate base because the amount by which IP determined the inventory had been depleted "is an estimate." (Staff Init. Br., p. 4) IP stated that the fact that the value is "an estimate" is not a basis to reject it, and that any impression that Staff was attempting to convey that "estimates" are not used in setting regulated rates would be fallacious. IP stated that estimates are frequently employed in setting rates. For example, one of the most significant components in the ratemaking calculation, the cost of common equity, is an estimate. IP noted that in this case the Staff cost of capital witness frequently referred both to her recommended cost of common equity and to many of the inputs she used in her analysis as "estimates". IP stated that, more generally, the entire concept of the test year revenue requirement is an estimate that the utility's adjusted, historical revenue requirement (for an historic test year) or its forecasted revenue requirement (for a future test year) will equal its actual revenue requirement during the period the new rates are in effect. IP cited other examples of the use of estimated values in setting rates, including the use of estimated asset service lives and salvage values to establish depreciation rates which are used to determine depreciation expense as well as the accumulated provision for depreciation; and pension expenses which are based on actuarial estimates. (IP Rep. Br., p. 30)

IP also pointed out that the use of estimates is not limited to setting the revenue requirement in a rate case. Once the revenue requirement is determined, the process of determining how much of the revenue requirement should be paid by each customer class is also an estimating process. IP pointed to Staff's statement at page 69 of its Initial Brief, citing Staff witness Lazare: "[I]t should be remembered that cost of service studies are an art, not a science. The results obtained are only estimates of the responsibility of customer classes for individual costs and often based on imperfect data as the Company's proposed services allocator demonstrates." Finally, IP noted that a number of Illinois gas utilities, including IP, bill their customers using estimated meter readings for six months of the year. (IP Rep. Br., pp. 30-31)

Illinois Power concluded that the overall inventory depletion value was based on a detailed evaluation of the available comprehensive data base and used state-of-the art, industry-accepted techniques, and that the value of 5.8 bcf, including the 1.8 bcf base gas inventory depletion amount, which has been reinjected, is reasonable and sufficiently reliable to use in establishing the base gas inventory value to be included in rate base in this proceeding. IP stated that there is no justification for adopting Mr. Lounsberry's recommendation to include only the 1993 value in rate base, which, IP pointed out, effectively assumes that no change to the Hillsboro base gas inventory value has occurred since 1993. IP concluded that its adjustment of \$1,908,000 to its booked December 31, 2003, base gas inventory, reflecting an overall adjustment of \$10,367,838 to the 1993 Hillsboro base gas inventory amount included in rate base in Docket 93-0183, should be accepted.

d. IP's Response to Staff's Prudence Argument

IP objected to Staff's introduction for the first time in its Initial Brief of its argument that IP's proposed adjustment to the Hillsboro base gas inventory should be disallowed because IP had not acted prudently. IP pointed out that in his direct and rebuttal testimonies, Mr. Lounsberry's only stated basis for his position that the increase in the base inventory value should not be allowed was that he did not think IP's calculation of the amount of the inventory depletion was accurate enough to use in setting rates. IP quoted numerous examples from Mr. Lounsberry's direct and rebuttal testimonies which it contended clearly demonstrated this, including pages 8, 16 and 19 of Mr. Lounsberry's direct testimony and pages 4, 5, 6-7, and 23-24 of his rebuttal testimony. IP emphasized that the only reason testified to by Staff witness Lounsberry for recommending that IP's Hillsboro base gas inventory amount not be adopted was that he did not agree that the base inventory amount determined by IP was sufficiently accurate. IP stated that nowhere in his testimony did Mr. Lounsberry contend that IP's base gas inventory amount should be disallowed because it resulted from imprudent management by Illinois Power. IP stated that because Staff contended for the first time in this case in its Initial Brief that IP's Hillsboro base gas inventory amount should be disallowed because it resulted from imprudent management actions, Staff's belated and untimely argument should be rejected by the Commission. (IP Rep. Br., pp. 1-4)

IP also pointed out that the evidence on which Staff, in its Initial Brief, relied on in support of its "prudence" argument was not presented in Staff witness Lounsberry's testimony in support of any prudence argument, but rather in support of his proposed used and useful adjustment for Hillsboro. IP stated that this evidence was presented by Mr. Lounsberry in subsections of his direct and rebuttal testimonies captioned "Overall Storage Concerns" which were part of the "Used and Useful" portion of his direct and rebuttal testimonies. IP cited excerpts from Mr. Lounsberry's direct and rebuttal testimony in which he made it clear that the "Overall Storage Concerns" section of his testimony only related to his proposed used and useful adjustment for Hillsboro. IP argued that although in a case before the Commission there may be purely legal issues (e.g., issues of statutory construction) that are not appropriate for substantive discussion in witness testimony, a proposed prudence disallowance is not such an issue. IP stated that a determination of a prudence issue requires analysis of management decisions and actions relating to the event in question based on the information available at the time the decisions and actions occurred, and therefore is specifically fact based. IP also stated that it cannot respond to disallowance theories that are not articulated in other parties' testimony. Further, IP argued that Staff's approach ignored the sequence of presentation of evidence and arguments in a rate case. IP stated that the utility makes its *prima facie* case in a rate case by presenting its cost of service. The burden then shifts to other parties to demonstrate that the utility's costs are unreasonable and should not be included in setting rates. If Staff or intervenors raise issues about specific components of the utility's costs, the burden shifts back to the utility to refute those issues and demonstrate that those costs are reasonable and prudent in light of the specific issues raised. (See, e.g., *City of Chicago*

v. Commerce Commission, 133 Ill. App. 3d 435, 442 (1st Dist. 1985)) IP stated that in this case, it responded in detail with the rebuttal and surrebuttal testimonies of three witnesses and witness panels to Mr. Lounsberry's articulated proposal to disallow IP's Hillsboro base gas inventory amount because the base inventory amount is not sufficiently accurate or reliable. IP reiterated that a utility cannot present evidence and arguments in response to issues about its costs that Staff and intervenors do not raise in their testimonies. (IP Rep. Br., pp. 4-6)

Thus, IP concluded that the Commission should reject Staff's "prudence" argument because it was not articulated in Mr. Lounsberry's direct or rebuttal testimonies, but rather was raised for the first time in Staff's brief. IP stated that this deprived it of the opportunity to respond to Staff's arguments and evidence in the context of a claim that IP's actions and decisions were imprudent. (IP Rep. Br., p. 7)

IP stated, however, that despite Staff's belated revelation of its prudence argument, the record contains ample evidence to demonstrate that IP's decisions and actions with respect to the Hillsboro deliverability decline (which resulted from the inventory depletion caused by the injection metering error) were prudent. IP pointed out that most of this evidence was never even responded to by Mr. Lounsberry. (IP Rep. Br., pp. 7-8)

i. The Standard for Prudence

IP stated that the starting point in evaluating Staff's prudence argument must be the well-recognized standard for prudence which this Commission has adopted:

Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. In determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered. Hindsight review is impermissible.

Imprudence cannot be sustained by substituting one's judgment for that of another. The prudence standard recognizes that reasonable persons can have honest differences of opinion without the one or the other necessarily being "imprudent." (*Illinois Commerce Commission v. Commonwealth Edison Co.*, Docket 84-0395 (Oct. 7, 1987), p. 17)

IP noted that this standard has been confirmed by the Illinois courts, citing *Illinois Power Co. v. Commerce Commission*, 245 Ill. App. 3d 367, 371 (3d Dist. 1993) (reversing a Commission finding of imprudence); *Illinois Power Co. v. Commerce Commission*, 339 Ill. App. 3d 425, 428, 435 (5th Dist. 2003) (reversing a Commission finding of imprudence that was based on Mr. Lounsberry's recommendation). (IP Rep. Br., p. 8)

IP stated that the Commission and the courts have also recognized that, when humans are involved, errors are reasonable to expect. (Order in Docket 84-0395, p. 19; *Business & Professional People for the Public Interest v. Commerce Commission*, 279 Ill. App. 3d 824, 833 (1st Dist 1996) (“a small amount of human error is an unavoidable cost of any human endeavor”)). IP also cited the Commission’s order in Docket 01-0701, which was the last IP case in which Mr. Lounsberry recommended a prudence disallowance for IP, supported in part by the “Overall Storage Concerns” he relied on in this case. (IP Rep. Br., pp. 8-9) IP pointed out that in that order, the Commission stated:

As indicated above, the Commission has previously defined prudence as the standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. (Order in Docket 01-0701, p. 22)

. . . This is not to say, however, that the circumstances identified by Staff and listed in [IP’s] Shanghai Report could not have been perceived by some at the time of their occurrence as warnings of potential problems in the future. The question, though, is whether in light of *all* of the circumstances at Shanghai, was IP imprudent in its failure to realize that Shanghai’s deliverability may be impaired in the future. (*Id.*, p. 23; emphasis in original)

. . . Admittedly, IP’s perception of Shanghai’s performance was obscured by an error in computer settings which affected the meters at Shanghai. As result of this error, IP withdrew 743,313 Mcf of gas above what its meters reflected from 1995 to 1999. Although this mistake was certainly avoidable, its detection was hampered by the results of an earlier well casing leak. IP acknowledges the error but argues that it cannot be expected to be perfect. The Commission agrees. The potential for human error is inherent in all human endeavors. Data input is obviously no exception. (*Id.*, p. 23)

. . . In light of the foregoing, the Commission is persuaded by IP that IP acted reasonably and prudently with regard to its decision to reduce the peak day deliverability of Shanghai by 25,000 Mcf/d for purposes of its 2001 PGA reconciliation. While certain errors occurred and hindsight shows that some of IP’s observations and beliefs were incorrect, a natural gas storage aquifer is a complex physical system and the Commission finds that under the circumstances IP’s actions with respect to Shanghai were not imprudent. (*Id.*, p. 25)

ii. IP’s Investigation of the Cause of the Hillsboro Deliverability Decline

IP noted that Staff's prudence argument focused on several specific assertions with respect to one of the withdrawal meters at Hillsboro. IP stated that Staff's specific assertions about the withdrawal metering are inaccurate or misplaced. Moreover, IP stated, the issues raised by Staff concerning the withdrawal metering had nothing to do with the cause, identification and correction of the injection metering error, which was the actual cause of the Hillsboro inventory depletion. IP stated that at the time the injection metering error was occurring, its manifestation was a decline in the deliverability performance of the Hillsboro Field, which was the problem IP was facing at the time the decisions and actions in question were being made and taken. Thus, IP stated, if there is to be a prudence issue in this case, what must be evaluated is the prudence of IP's efforts to identify and correct the deliverability decline that IP was facing subsequent to the 1993 expansion of the Hillsboro Field, not just IP's specific actions with regard to the metering error (which is the focus of Staff's prudence argument). IP stated that only in hindsight was it known that the cause of the Hillsboro deliverability decline (and thus of the inventory depletion) was a turbine injection metering error. (IP Rep. Br., p. 10)

IP stated that the record in this case demonstrates that it acted aggressively and proactively, and expended considerable resources, in attempting to identify and resolve the causes of the Hillsboro Storage Field deliverability decline. These efforts resulted in the identification and correction of the injection metering measurement error that was the cause of the Hillsboro inventory depletion and thus of the Field's performance decline. IP noted that its witnesses Hower, Hood and Kemppainen presented testimony describing IP's efforts to identify and resolve the causes of the Hillsboro deliverability problems. IP pointed out that Mr. Kemppainen and Mr. Hower were directly involved in IP's efforts to identify the causes of the Hillsboro deliverability decline, and that their discussions of the history of the efforts to eliminate the Hillsboro deliverability problems brought a real-time perspective to the record that was not provided by Mr. Lounsberry's hindsight assessments. (IP Rep. Br., pp. 10-11)

(a) IP's Identification of a Potential Deliverability Problem at Hillsboro

IP stated that as a result of the expansion of Hillsboro, which was completed in 1993, the peak day deliverability of the Field was increased to 125,000 mcf/day and its expected working gas volume was increased to 7.6 bcf. (Rev. IP Ex. 14.1, p. 4) IP indicated that initially, the expanded Field performed as expected. For the 1993-1994 through 1996-1997 heating seasons, Hillsboro tested at a peak day deliverability value of 125,000 mcf/day or greater in each of these seasons; and for the 1993-1994 winter, approximately 7.6 bcf of gas was withdrawn for delivery to customers. In winters subsequent to 1993-1994, however, the amounts of gas withdrawn from the Field for delivery to customers declined. (*Id.*, p. 5) IP stated that based on several years of declining annual deliverability, IP first observed that there could be a potential problem with Hillsboro following the 1995-1996 winter withdrawal season (i.e., after the third year of operation of the expanded Field). (Rev. IP Ex. 14.1, p. 5) IP witnesses Hood and Kemppainen explained that a low amount of gas withdrawals in a single inject-withdraw cycle would not necessarily lead one to suspect a problem, since exogenous factors

such as weather and other load constraints could impact the volume of gas cycled in a given year. They noted that, at least one of the early years was warmer than normal, meaning that withdrawing less than 7.6 bcf in the winter season would not be unusual. They stated that observation of reduced or declining deliverability over several years would be necessary for the storage field operator (i.e., IP) to suspect that there could be a physical or operating problem that was reducing deliverability. (*Id.*, pp. 5-6) IP noted that Mr. Lounsberry did not fault IP for not recognizing and commencing its investigation of the Hillsboro deliverability decline sooner than 1996. (IP Rep. Br., pp. 11-12)

(b) IP's Investigation of a Potential Structural Cause for the Hillsboro Deliverability Decline

IP stated that it initially focused its investigation on whether there was a reservoir problem with the Hillsboro Storage Field, that is, whether either (i) gas injected into the Field was migrating from the underground structure, or (ii) the shape of the underground structure was different than what had been expected. The result in either situation would be that gas injected into the Field was moving or being pushed to areas where it could not be reached by the withdrawal wells. (Rev. IP Ex. 14.1, p. 6) IP pointed out that Mr. Lounsberry did not fault IP for initially focusing on a possible reservoir problem as the source of Hillsboro's declining deliverability. To investigate this possibility, IP had a vertical seismic profile of the Field prepared by outside consultants. Based on this analysis, which concluded that a 3-D seismic profile would be a viable means to define the structure of the Field, IP retained an external consultant to conduct a 3-D study. The preliminary results of the 3-D seismic study, conducted in 1998, indicated that approximately 3.5 bcf of gas had migrated to another underground structure to the northeast of the Hillsboro Field. (*Id.*, p. 7; IP Ex. 12.5)

IP stated that based on the results of the 3-D seismic analysis of the Hillsboro Field, IP drilled a new well to the northeast of the Field where the 3-D analysis indicated a sub-structure, or second geological structure, existed to which gas had migrated from the main reservoir. The new well was drilled to confirm the existence of the second geological structure and to access the gas believed to be in the second structure in order to restore deliverability to the Field. Upon completion of this well, however, in 2000, it was discovered that there was not in fact a separate sub-structure in that area. (Rev. IP Ex. 14.1, pp. 11-12) IP noted that Mr. Lounsberry did not fault IP for drilling this new well in an effort to locate the indicated off-Field substructure. (IP Rep. Br., p. 13)

IP stated that after drilling the new well, it conducted a number of additional studies and investigations to determine if there was a structural cause for declining deliverability of the Hillsboro Field. In June 2001, IP had an outside consultant perform a crosswell seismic survey involving four wells at Hillsboro. (As described earlier in this Order, a crosswell seismic survey is a high resolution process capable of resolving features much smaller than those visible with 3-D surface seismic analysis.) IP stated that this analysis helped to confirm that there was not in fact an additional geologic

structure to the northeast of the existing underground structure. (Rev. IP Ex. 14.1, pp. 12-13)

IP stated that additionally, over the period from November 2000 through November 2002, it performed well stimulation treatments on a total of six wells at the Hillsboro Field. IP explained that well stimulation treatments consist of injecting chemicals into a well bore, and thus into the underground reservoir, in an effort to clean up any barriers near the well bore that may be restricting injection or withdrawal of gas. These restrictions can be caused by such things as drilling, casing, cementing operations, perforating, solids invasion, scale, fines migration, emulsions or bacteria. Well stimulation treatments use acids, surfactants and other proprietary chemicals to remove the barriers or restrictions in the underground formation and restore the productivity of the well. (Rev. IP Ex. 14.1, pp. 13-14)

IP stated that it also performed additional neutron log analyses, which are surveys conducted inside a gas well that can determine the water-gas mix within the reservoir by measuring the hydrogen ion concentration. The neutron logs were analyzed to determine if there was leakage from the reservoir to a shallower formation, but they did not indicate any leakage was occurring from the formation. Additionally, information from the neutron logs on the thickness of the gas bubble in the Hillsboro reservoir was compared to similar information from neutron logs conducted in previous years; this comparison indicated that the gas bubble in the reservoir was thinning. (Rev. IP Ex. 14.1, p. 14; IP Ex. 17.1, p. 8) IP stated that it also conducted flame ionization surveys, which are tests conducted at ground levels to identify any migration of gas at the surface that would not be detected through the neutron logs. These surveys detected no identifiable gas leakage at the surface of the Field. (Rev. IP Ex. 14.1, p. 14) Further, IP performed analyses to determine if gas being withdrawn was actually recirculating through the plant equipment and back in to the Field; however, it was determined that this was not occurring. (*Id.*, p. 15)

IP also conducted analyses of water levels and water production at Hillsboro's observation wells over time. These analyses indicated that the volume of gas in the reservoir was decreasing. However, these analyses also showed that the working gas volumes in the reservoir had declined to below the 3.6 bcf working gas volume of the Field prior to the 1993 expansion. IP stated that this observation indicated that the source of the deliverability decline was not structural, because if the cause of the problem were structural, the working gas volumes would have stabilized at the pre-expansion levels of 3.6 bcf. (*Id.*, p. 15) Finally, a volumetric analysis was conducted, using data on the volume of the reservoir and gas saturation data from the reservoir to develop an estimate of gas volumes actually in the reservoir at different points in time. A comparison of gas volumes in the Field in the spring of 1993 and in the spring of 2002, calculated using this method, showed that there was approximately 5.5 bcf less gas in the Field in the spring of 2002 than in the spring of 1993. (*Id.*, pp. 15-16)

IP stated in summary that it conducted numerous separate studies and analyses and pursued a number of different possibilities in attempting to determine if the cause of

the Hillsboro deliverability decline was a structural problem with the recently-expanded reservoir and if so, what the specific problem was. IP stated that this was a logical and plausible area of investigation to pursue given that Hillsboro had undergone a significant expansion in 1993 but after that expansion was not performing as anticipated. IP also pointed out that it expended considerable internal and external resources on these investigations and analyses. IP noted that Mr. Lounsberry did not contend that any of these analyses were unnecessary, inappropriate or ill-advised or that focusing on a possible structural or geological problem as the cause of the declining performance of the recently-expanded Field was not prudent or appropriate. IP stated that the investigations and analyses into whether there was a potential structural problem led to the ultimate conclusions that (i) the volume of gas in the Hillsboro reservoir had declined significantly since 1993, but (ii) the cause of the volume decline was not a structural problem or other physical problem (e.g., leakage through plant equipment, through the surface or into another underground formation). (IP Rep. Br., p. 15)

(c) IP's Investigation of a Possible Metering Cause for the Hillsboro Deliverability Decline

IP stated that contemporaneous with investigating whether there was a structural cause for the Hillsboro deliverability decline, it also separately investigated whether there could be a metering problem. In 1999, while still investigating possible structural causes (and planning to drill the additional well to access the reservoir formation believed to exist to the northeast of the Field), IP retained an outside engineering consulting firm, Peterson Engineering, to conduct an audit of the metering at the Hillsboro Field. (Rev. IP Ex. 14.1, pp. 7-8) IP stated that Peterson Engineering's report, issued in December 1999, identified two metering problems.

The first problem identified by Peterson was that two new turbine injection meters that had been installed at Hillsboro were over-registering gas injections under certain operating conditions due to the operation of compressors that were located nearby. (The turbine meters were the main plant meters by which gas coming into the Hillsboro Field for injection was measured.) When the compressors were operating at approximately 50% loadings, they caused the turbine meters to over-spin, thereby recording a greater amount of gas than was in fact passing through the meters. As a result, over time the turbine injection meters were recording more gas as injected into the Field than was in fact occurring. IP stated that the turbine meter over-registration was determined to be 26% when the compressors were operating at 50% loadings, while the over-registration was minimal when the compressors were operated at close to full loadings. (Rev. IP Ex. 14.1, p. 8)

The second problem identified by Peterson was that the orifice opening on one of the plant withdrawal meters was smaller than the value that had been stamped on the equipment at the manufacturer's plant. The orifice opening value stamped on the equipment was the opening size that IP had ordered, but the size of the opening was actually smaller than the value stamped on the orifice plate. This meant that less gas was being withdrawn from the Field than had been believed, because the size of the

orifice opening is a value that is input into the meter's programmable logic controller that calculates the value of gas being withdrawn through the meter. (Rev. IP Ex. 14.1, pp. 8-9) IP stated that the meter in question was on the "secondary" withdrawal run into the south pipeline from the Hillsboro Field. The principal gas withdrawal facility into the south outbound pipeline is the "primary" run. (There is also a north primary and secondary withdrawal run.) IP noted that the secondary run only operates occasionally, during periods of high withdrawal flow rates. (*Id.*)

IP stated that to correct the turbine injection metering measurement errors, it implemented operating procedures to avoid the 25% and 50% compressor loading levels, since these were the compressor loading levels that caused the most significant over-registration on the turbine meters. Additionally, the static pressure sensing point for the turbine meters was relocated in order to improve their accuracy. IP stated that both of these actions were recommended in the Peterson Engineering report. These steps were implemented in May 2000 (i.e., early in the injection season for the 2000-2001 winter). (Rev. IP Ex. 14.1, p. 10) Thus, IP stated, by early 2000, the turbine injection metering problem, which was ultimately determined to have been the cause of the Hillsboro deliverability declines and the gas inventory depletion, had been corrected. (IP Rep. Br. p. 17) To correct the problem of the incorrect opening size on the orifice meter, the correct value for the orifice opening was input into the programmable logic controller so that it would correctly calculate the amount of gas being withdrawn through the meter. (Rev. IP Ex. 14.1, pp. 10-11) The withdrawal plates on all of the Hillsboro orifice meters were inspected, were determined to still be service-worthy, and were re-installed. (*Id.*, p. 35)

IP noted that at the time of the Peterson Engineering review, the injection metering error at the turbine meters and the withdrawal metering error on the south pipeline secondary withdrawal meter were treated as offsetting. IP stated that the amount of the measurement error at the withdrawal meter could be calculated with great accuracy, because the amount of the error was simply a function of the difference between the correct and incorrect opening sizes. (Rev. IP Ex. 14.1, p. 11) That is, knowing the correct size of the orifice opening versus the incorrect size that had been used in the programmable logic controller, the actual volume of gas that had passed through this meter over time could be calculated. In contrast, at this time IP was only able to develop a range of potential measurement errors on the turbine injection meters based on the compressor loadings. The bottom end of that range was about 2%, or approximately equal to the calculated orifice withdrawal meter errors. (*Id.*) As a result, IP did not believe it had a sufficient basis to make a gas inventory correction at that time. (*Id.*) IP emphasized that the identification of the turbine injection meter over-spin problem relating the operation of the compressors, and the implementation of the corrective actions recommended by Peterson Engineering, as described above, essentially ended the injection metering measurement error as of the start of the 2000 injection season. (*Id.*, p. 16)

(d) Identification of the Injection Metering Error and Inventory Depletion as the Cause of the Deliverability Decline and Implementation of Actions to Restore the Field

IP stated that it continued to investigate possible structural causes for the Hillsboro deliverability decline after 2000. The volumetric analysis performed in 2002, described above, calculated that the amount of gas in the Field had been depleted by approximately 5.5 bcf since 1993. (Rev. IP Ex. 14.1, pp. 15-16) In addition, a comparison was performed of the gas measured on the plant turbine injection meters for specified time periods to the gas injected at the individual wells as measured by injection metering at the individual wells, for the same time periods. IP stated that this comparison showed that the turbine meters had been recording substantially more gas as injected into the Field than had actually been injected, over an extended period of time. (*Id.*, pp. 15, 16) Further, the analyses IP conducted to determine if the deliverability decline was caused by a structural problem enabled IP to rule out the likelihood that the source of the gas inventory depletion was a structural or geological problem. (*Id.*, p. 16) Accordingly, IP concluded that the cause of the Hillsboro deliverability decline was that the gas inventory in the Field had been substantially depleted as a consequence of the injection metering error occurring over time. (*Id.*, pp. 16-17) IP determined that it would be necessary to restate the gas volumes actually in the Field from the volumes shown on IP's accounting records (which were based on the injection metering), and that to return to the design characteristics of the Field, the proper inventory levels must be restored. (*Id.*, p. 17; IP Ex. 14.2, p. 1; Rev. IP Ex. 13.1, pp. 4-5; IP Ex. 2.1, p. 17) IP indicated that the specific actions required were to (1) determine the gas inventory shortfall that had resulted from the injection metering error; (2) restore the base gas inventory volume to the original (post-expansion) 1993 amount of 14.1 bcf; and (3) reinject gas to restore the 1993 working gas volume of 7.6 bcf. (Rev. IP Ex. 14.1, p. 17) A plan was developed for reinjecting the depleted base and working gas amounts into the Field; reinjections were initiated during 2003. (Rev. IP Ex. 14.1, p. 18; IP Ex. 14.2, p. 1) IP stated that reinjection of the base gas has been completed, and reinjection of the full working gas amounts is to be completed during the 2006 injection season. (Rev. IP Ex. 13.1, p. 5; Rev. IP Ex. 14.1, p. 18; IP Ex. 14.2, p. 1) IP noted that the reinjections planned for 2004 were successfully completed. (Rev. IP Ex. 13.1, p. 9) Additionally, prior to the start of the 2003-2004 winter season, IP restored the peak deliverability rating of Hillsboro to 125,000 mcf/day. (Rev. IP Ex. 14.1, p. 19)

IP concluded that its actions as summarized above showed that IP acted prudently in investigating the cause of the Hillsboro deliverability decline, isolating and eliminating potential causes, and ultimately identifying the cause, implementing corrective actions to eliminate it and developing and implementing a plan to restore Hillsboro to its 1993 design parameters. IP contended that it was extremely proactive in trying to identify and correct the root causes of the Hillsboro deliverability and inventory problems. (Rev. IP Ex. 13.1, p. 19) IP emphasized that it investigated multiple possible causes for the deliverability decline, including structural or geological causes (from a real-time perspective, the most likely source of the problem for a storage field that had

just undergone a significant expansion), obstructions in the well bores that restricted access to gas in the Field, and metering errors. IP stated that multiple analyses were pursued on parallel paths. Outside resources (external engineering and geological consulting firms) as well as internal resources were brought to bear on the problem. Corrective actions recommended by outside consultants for identified problems were implemented. Potential causes of the deliverability decline were eliminated based on the results of these analyses, until IP ultimately determined that the cause of the deliverability decline was the depletion of the gas inventory in the Field resulting from the turbine injection metering error. (IP Rep. Br., p. 20)

IP noted that Staff witness Lounsberry did not criticize any of the above-described specific studies or analyses IP performed, the need for or appropriateness of those analyses, or the timing of when they were conducted. IP concluded that the record demonstrated that in investigating, and ultimately identifying and resolving, the cause of the Hillsboro deliverability decline, IP exercised the standard of care that a reasonable person would be expected to exercise under the circumstances encountered by management at the time its decisions were being made and actions being taken, based on the facts available at those times. (IP Rep. Br., pp. 20-21)

iii. IP's Response to the Specific Concerns Cited by Staff in Support of its Prudence Argument

IP stated that the specific concerns raised by Staff witness Lounsberry, as cited pages 21-22 of Staff's Initial Brief, do not demonstrate that IP acted imprudently or that it should be denied recovery of the costs of the reinjected base gas. In its Reply Brief, IP addressed each of these items. (IP Rep. Br., pp. 21-27)

IP responded to Staff's assertion that "one cause of the measurement errors was an accuracy problem resulting from the orifice opening being smaller than [sic] the value stamped on the orifice plate utilized on IP's withdrawal meters." IP stated that this assertion is completely inaccurate. IP pointed out that the measurement error that resulted in the inventory depletion occurred solely at the plant turbine injection meters. (IP Ex. 14.3, p. 18) IP noted that since the error in withdrawal measurement due to the incorrectly sized orifice opening was 2%, while the turbine injection metering error provided to be many times that, there is no basis to conclude that earlier detection of the erroneously-labeled orifice opening would have led to earlier discovery of the turbine metering problem. IP also stated that Staff's assertion is further factually inaccurate because there was an incorrectly labeled orifice plate on only one of the four withdrawal meters, not all of them. (IP Rep. Br., pp. 21-22)

IP contended that Staff's assertion that "the metering errors related to the orifice meters would have been discovered shortly after their installation if the Company had followed some basic industry standards" was erroneous and misleading on multiple levels. First, the withdrawal metering error related to only one of the four orifice withdrawal meters. Second, Staff relied on inapplicable standards. One of the "basic industry standards" cited by Mr. Lounsberry was 83 Ill. Administrative Code Part 500,

whose provisions, Mr. Lounsberry testified, “apply only to utility meters used to measure customer load.” (Staff Ex. 7.0, p. 47) IP noted that Mr. Lounsberry further admitted that “the Part 500 requirements to [sic; do] not apply to storage field orifice meters” and “I am not suggesting that IP violated a Commission rule”. (*Id.*, p. 49; emphasis supplied) (IP Rep. Br., p. 22)

IP noted that the other “basic industry standard” cited by Mr. Lounsberry is “AGA Report #3” which contains certain provisions quoted at page 46 of Staff’s Initial Brief. IP pointed out, however, that Staff admitted that “AGA Report #3 contains the guidelines for the installation of orifice meters.” (Staff Init. Br., p. 46) That is, AGA Report #3 does not cover maintenance or testing of orifice meters. (Rev. IP Ex. 14.1, p. 34) IP pointed out that Staff made no contention that the guidelines of AGA Report #3 were not complied with when the Hillsboro orifice meters were installed. In fact, IP noted, the same Peterson Engineering report cited by Staff concluded with respect to the withdrawal metering installations at Hillsboro, “In general, the metering layout is well designed and is in general conformance with AGA Report #3, Part 2” (Rev. IP Ex. 14.1, p. 36). In other words, the orifice station metering at Hillsboro was designed and installed to the standards of AGA Report #3. (*Id.*) IP also stated that although Mr. Lounsberry and Staff cite an observation in the Peterson Engineering report that when the plates on the four orifice withdrawal meters were pulled and inspected they were dirty to varying degrees (Staff Init. Br., pp. 46-49, citing Staff Ex. 7.0, p. 49), the fact is that all of the orifice plates were found to be not degraded and were still service-worthy. (Rev. IP Ex. 14.1, p. 35) IP pointed out that Staff had identified no evidence that the “dirty” condition of these plates caused any measurement error, and that the only withdrawal measurement error occurred due to the incorrectly labeled orifice opening on one of the four withdrawal meters. (IP Rep. Br., p. 23)

IP also responded to Staff’s statement at page 47 of its Initial Brief that “Staff, through its enforcement of Part 500, ensures every Illinois utility follows the intent of the requirements contained in that section.” IP noted that the enforcement arm of Staff did not believe that IP needed to follow the inspection and testing requirements of Part 500 for its storage field orifice meters, since Staff cited no notices of violation or noncompliance issued by the Commission’s OPS to IP on this topic. IP stated that as a result of OPS’ annual audits of all seven of IP’s storage fields, the OPS has issued only one “Non-Compliance” and two “Observations” to IP over the past five years, all of which were minor in nature and quickly addressed. (Rev. IP Ex. 13.1, p. 18; IP Rep. Br., pp. 22-23)

IP reiterated that, putting aside the fact that Mr. Lounsberry and Staff did not cite any maintenance and inspection standards that are in fact applicable to the Hillsboro orifice withdrawal meters, the problem with the orifice withdrawal meter at Hillsboro was not caused by any deterioration due to lack of maintenance, but rather was due to the fact that although the label stamped on the orifice plate in question by the manufacturer stated that the orifice opening was the size that IP had ordered, in fact the orifice opening was somewhat smaller than the labeled (and ordered) size. (IP Ex. 14.3, p. 17) IP also noted that it did have specific annual inspection and calibration procedures for

the Hillsboro orifice meters (Rev. IP Ex. 14.1, pp. 34-35), and that Staff did not criticize the procedures that IP did have in place. (IP Rep. Br., p. 24)

IP also argued that since the issue raised by Staff was prudence, which is to be judged under a reasonable person standard and without substitution of one person's judgment for another's judgment, Staff failed to explain why IP should have been expected to expend the effort and expense (which presumably it would be entitled to recover from its customers) to operate and maintain its storage field metering in accordance with regulations, standards and guidelines that by their terms are not applicable to storage field metering. IP stated that such a course would seem imprudent rather than prudent, and inconsistent with the efficient and least-cost operation of IP's facilities. IP also pointed out that Staff presented no evidence that other Illinois gas utilities are incurring the additional expense necessary to operate and maintain their storage field metering in accordance with regulations, standards and guidelines that by their terms are not applicable. (IP Rep. Br., pp. 24-25)

IP stated that Staff's assertion that IP's failure to inspect its orifice meters more frequently, "thereby prevent[ing] the discovery of this problem", had the effect of "clearly contribut[ing] to the measurement errors that drove the need to use recoverable base case [sic; gas] to serve current load", was unsupported by the record. IP reiterated that it was the turbine injection metering error, not the incorrectly labeled orifice plate on one of the lesser used of the four withdrawal meters, that caused the Hillsboro inventory depletion. IP pointed out again that the withdrawal metering error induced by the incorrectly labeled orifice opening was only about 2% whereas the turbine injection metering error was many times that amount. The withdrawal metering error only mitigated the injection metering error by about 14%. (IP Ex. 14.3, p. 18) IP also noted that since the actual (but incorrectly labeled) orifice plate opening only produced a 2% withdrawal measurement error as compared to what would have been recorded had the opening been the size labeled on the orifice plate, the variance between the actual opening and the labeled size might not have been observable on visual inspection. (IP Rep. Br., p. 25)

IP stated that each of the specific facts that Staff cited as evidence of imprudence related to the orifice withdrawal meters and not to the turbine injection metering that was the actual cause of the measurement error and the inventory depletion. IP pointed out that Staff cited no evidence of inappropriate installation, operation or maintenance practices, or any other putative evidence of imprudence, with respect to the turbine injection meters themselves. (IP Rep. Br., p. 25)

IP responded to Staff's assertion that "IP's load forecasting and dispatch group failed to notice the variance between the volumes of gas received from the pipelines and the amount measured at its Hillsboro storage field", a bcf of gas on average for six years. (Staff Init. Br., p. 22) IP pointed out that it had fully responded to this assertion as presented as one of Mr. Lounsberry's "Overall Storage Concerns", specifically "Gas Dispatch Tracking". IP noted that it had explained that Mr. Lounsberry's assertion relating to "Gas Dispatch Tracking" was unsupportable when analyzed in the context of

operational realities and the daily volumes (and sources thereof) on IP's gas system (which is the context in which a prudence analysis must be conducted). IP noted that the average Hillsboro injection metering error of about 4,000 mcf per day was less than either (i) the amount of line pack typically in IP's gas system, or (ii) the potential daily variance between transportation customers' nominations and deliveries as allowed under IP's transportation tariff. IP concluded that this assertion by Staff is clearly hindsight oriented. (IP Rep. Br., pp. 25-26)

IP responded to Staff's reliance on Mr. Lounsberry's testimony in which he compared the average injection measurement error of 4,000 mcf/day (equal to about 40,000 therms/day) to the "system throughput for non-transportation customers" on a July day of about 295,000 therms. (Staff Init. Br., p. 51, citing Staff Ex. 17.0R, p. 49) IP stated that this comparison was baseless. Specifically, the "throughput for non-transportation customers" to which Mr. Lounsberry limited his example would be only a portion of the volumes that the gas dispatchers would see entering IP's system on a July day. IP stated that the total gas volume entering IP's system from the pipelines, including both gas for non-transportation customers and gas of transportation customers, would be about 105,000 mcf/day; on a real-time basis, the gas dispatchers would not be able to distinguish between deliveries for transport customers and deliveries for non-transport customers. Further, although the dispatchers know the total pipeline deliveries on a given day, they do not know the actual customer consumption on a given day to enable them to compare total deliveries to total usage. This is primarily because the vast majority of customers are not metered (or read) on a daily basis, but only on a non-calendar month monthly cycle basis. (See Rev. IP Ex. 13.9, p. 19) IP also stated that in addition to the gas entering its system intended for end users, gas would be entering IP's system on a July day for injection into its storage fields. IP stated that in total, the amount of gas entering its system on a July day could be 220,000 to 280,000 mcf, in contrast to the average daily Hillsboro injection metering error of 4,000 mcf, which would not be noticeable against these total incoming daily volumes. (Rev. IP Ex. 13.9, pp. 18-19) IP concluded that Mr. Lounsberry's contention that IP's gas dispatchers should have been able to detect the amount of gas being received into IP system but not injected into Hillsboro was unrealistic and unsupported by the record, in light of the totality of the gas volumes on IP's system on a daily basis and the other variables affecting the daily load. (IP Rep. Br., pp. 26-27)

e. IP's Response to Mr. Lounsberry's Position that IP Should Seek Recovery of the Additional Base Gas Cost Through the PGA

Illinois Power responded to Staff witness Lounsberry's testimony that IP should seek to recover the \$10,367,838 increased cost of Hillsboro base gas inventory through the PGA rather than including the revised base gas inventory cost in rate base. IP stated that this position is at odds with the Commission's PGA rule and is unfounded. IP stated that while it is currently recovering through the PGA the cost of the original Hillsboro base gas that was withdrawn from storage and supplied to customers, the \$10,367,838 amount is the cost of the gas that has been reinjected into the Field to

restore the base gas inventory volume. (Rev. IP Ex. 13.1, p. 6) Ms. Carter, AmerenIP's Manager of Accounting pointed out that Section 525.40(c) of the Commission's PGA rule (83 Ill. Adm. Code 525.40(c)) states: "The cost of gas estimated to be withdrawn from storage during the base period shall be included in the Gas Charge(s)." She explained that the \$10,367,838 of base gas in question was not injected into the Hillsboro Field with the intention of withdrawing it to supply customers, and it has not in fact been withdrawn from storage to serve customers. Therefore, she concluded that the cost of this base gas should be recovered through IP's base rates as a rate base component), not through its PGA. (Rev. IP Ex. 2.35, pp. 52-53) IP pointed out that Mr. Lounsberry did not address the Commission's PGA rule in making his recommendation and did not respond to Ms. Carter's testimony. Also, Staff did not present any testimony from any witness from the Accounting Department or Financial Analysis Division of the Commission to contradict Ms. Carter's analysis of the Commission's PGA rule or to support Mr. Lounsberry's proposal. IP concluded that Mr. Lounsberry's proposal for PGA recovery rather than base rate recovery was completely unfounded and should be rejected.

IP noted that while Staff contended that base gas is typically not expected to be withdrawn until the storage field is retired, that is not what has happened in this case. The original base gas was withdrawn and supplied to customers and new base gas has subsequently been injected to replace it. IP pointed out that Staff did not cite any Commission rule or order or other binding provision of law that prohibits the withdrawal of recoverable base gas prior to retirement of a storage field or that requires that the value of a storage field's recoverable base gas be set when the field first goes into service and not be changed thereafter. (IP Rep. Br., pp. 27-28)

IP disagreed with Staff's assertion that including the cost of the reinjected base gas in rate base, rather than collecting it through the PGA, would result in "unnecessary increased costs for ratepayers." IP stated that there is no dispute that the withdrawn original base gas was supplied to customers, and that it was less costly than supplying the same amount of gas through current purchases. Thus, customers benefited from having received this amount of gas supply at a lower price. With respect to the cost of the reinjected base gas, IP stated that the choice is having customers pay for it currently (or in the near future) through the PGA versus, in essence, paying carrying costs on this gas (through return on rate base) until such future time as the base gas is withdrawn from storage and supplied to customers. IP stated that assuming that the rate of return on rate base accurately represents the cost of capital, this choice should be a matter of indifference to customers on a present value basis. (IP Rep. Br., p. 29)

3. Commission Conclusion

Based on its review of the record and the arguments of Staff and Illinois Power, the Commission concludes that Illinois Power's base gas inventory value for Hillsboro should be accepted and included in rate base, and that Mr. Lounsberry's recommendation to reject IP's base gas inventory value for Hillsboro, and use instead the Hillsboro base gas inventory value that was included in rate base in IP's last gas

rate case, Docket 93-0183, should not be accepted. The Commission finds that the amount by which the Hillsboro recoverable base gas inventory was depleted due to the turbine injection metering error, 1.8 bcf, as determined by IP, was developed in a thorough and comprehensive manner using multiple analyses that included state-of-the-art techniques, particularly the reservoir modeling technique, which are accepted in the gas and oil industry as appropriate and reliable for determining the amount of gas or oil in place in an underground reservoir. Furthermore, the record shows that the reservoir simulation that IP developed for the Hillsboro Storage Field, with the assistance of outside consultants, was constructed using a broad and extensive data base of known information about the history and performance of the Hillsboro Field. The Commission finds that the Hillsboro recoverable base gas inventory value as determined by Illinois Power is sufficiently reliable to be utilized for ratemaking purposes. The Commission recognizes, as argued by Staff, that the 1.8 bcf value and the total inventory shortfall value of 5.8 bcf are ultimately estimates. However, the fact that the 1.8 bcf base gas inventory depletion amount is an estimate does not disqualify it from being used as an input in setting regulated rates. As shown by IP, estimated values are commonly utilized in numerous respects in the ratemaking process. The real issue is whether an estimate is developed in such a manner as to lead one to have confidence in the resulting product as a sufficiently reliable measure of the value to be included in calculating the revenue requirement. Based on its consideration of the record, the Commission concludes that the Hillsboro recoverable base gas inventory depletion amount determined by IP, 1.8 bcf, is sufficiently reliable to be used in setting IP's gas rates this proceeding. The Commission notes that if there is any subsequent change in this value as a result of further analysis or experience by IP, any necessary adjustment can be addressed in a future rate case.

The Commission has thoroughly considered the various concerns expressed by Staff with respect to IP's proposed 1.8 bcf Hillsboro base gas inventory depletion value and the manner in which Illinois Power determined that value, as well as IP's responses to Staff's concerns. The Commission concludes that Staff's concerns do not diminish our confidence in the overall reliability of the value developed by Illinois Power to render it unacceptable for use in setting the revenue requirement and, more importantly, for inclusion in gas rate base. The Commission notes Staff's concerns in particular regarding the "well chart analysis" employed by Illinois Power, but also notes that this was the method on which IP placed the least reliance and that IP placed the heaviest reliance on the reservoir simulation modeling and results, with the overall Hillsboro inventory shortfall value that IP developed being the same as the value produced by the reservoir simulation modeling technique.

The Commission also does not adopt Staff's recommendation that Illinois Power should be required to seek recovery of the additional cost of the replacement base gas through its Purchased Gas Adjustment clause. The Commission agrees with IP that under the Commission's PGA rule, particularly 83 Illinois Administrative Code 525.40(c), and the circumstances of this case, it would be inappropriate to recover through the PGA gas that has been injected into the storage field as base gas with no intention to withdraw it to supply to customers. Similarly, the Commission does not agree that IP

should be allowed to include only the original base gas inventory value in rate base on the theory that base gas after being injected into a storage field is not withdrawn until the storage field is retired. The Commission notes that the original base gas injected into the Hillsboro Storage Field has in fact been withdrawn and supplied to customers.

Finally, the Commission concludes that the record establishes the prudence of Illinois Power's actions in connection with the investigation and resolution of the declines in the deliverability of the Hillsboro Storage Field that resulted from the depletion of the storage field inventory which in turn was caused by the turbine injection metering error. The record demonstrates that IP acted aggressively and proactively, and expended considerable resources, in attempting to identify, and ultimately identifying and resolving, the causes of the Hillsboro Storage Field deliverability decline. Based on the record, the Commission concludes that IP's actions and decisions met the standard of prudence that the Commission has adopted. The Commission also notes that it would have made for a better record for Staff to have articulated its prudence argument specifically in its testimony in this case rather than articulating it for the first time in its briefs in this case. Nevertheless, the Commission has carefully considered all of Staff's arguments relating to prudence in arriving at its conclusions on this issue but concludes that the record does not establish that Illinois Power acted imprudently or that the increased base gas inventory value determined by IP should be excluded from rate base on grounds of any imprudence.

C. Hillsboro Storage Field Used and Useful Status

1. Staff's Position

2. AmerenIP's Position

a. Summary

It is Illinois Power's position that the Hillsboro Storage Field is fully used and useful and that Mr. Lounsberry's proposed used and useful adjustment is flawed and should be rejected by the Commission. IP's position is that in its current operating condition, which will be the operating condition of the Field when the new rates approved in this case go into effect, Hillsboro meets the statutory test of being "necessary" to meet customer demand and "economically beneficial" in meeting customer demand. IP stated that even using, without change, Mr. Lounsberry's calculation of the gas cost savings produced by the Hillsboro Field in its reduced operating condition (which IP believes is an inaccurate calculation that uses inappropriate prior period data), the annual gas cost savings that the Hillsboro Field provides for ratepayers through the PGA are greater than the annual revenue requirement associated with fully including the Field in rate base as 100% used and useful. It is also IP's position that Hillsboro is "necessary" because it provides winter season deliverability of gas that most likely could not be replaced through purchases of additional FT capacity from the interstate pipelines. (IP Init. Br., pp. 29-30)

It is also IP's position that Mr. Lounsberry's specific calculations leading to his 53.44% used and useful calculation were flawed and inappropriate for numerous reasons. IP contended that although Mr. Lounsberry purported to use the three-year period 2001-2002 through 2003-2004 for his calculations based on prior Commission orders addressing used and useful issues, analysis of prior Commission orders demonstrates that in the context of this case the three-year period 2002-2003 through 2005-2006 should be used. IP also pointed out that by using an earlier three-year period, Mr. Lounsberry failed to properly reflect the current capability of the Field, and he thereby produced an understated used and useful percentage. IP also stated that for the price of additional pipeline FT capacity assumed in his calculations to be needed to make up for Hillsboro's reduced deliverability, Mr. Lounsberry used the price of an intrastate pipeline and thus failed to include the cost of interstate pipeline transportation from the gas producing fields in the mid-continent region or the Gulf Coast region to Illinois. IP stated that Mr. Lounsberry's calculations therefore severely understated the cost savings provided by Hillsboro's peak day deliverability. Additionally, IP stated that Mr. Lounsberry's calculation of the seasonal gas savings produced by the Field was based on historic gas prices that were as much as five years old; therefore, the seasonal gas savings he calculated were unrepresentative of the seasonal gas cost savings produced by the Field based on current gas prices. IP stated that with these flaws corrected, application of Mr. Lounsberry's method shows Hillsboro to be no less than 84.33% used and useful. (Rev. IP Ex. 13.1, p. 14; IP Ex. 13.4)

IP also argued that although the underlying premise of Mr. Lounsberry's proposed used and useful disallowance is that the Field is not performing at the design levels represented to the Commission when the investment in the expanded Field was placed into rate base, he failed to use the relative weighting of the Field's peak day capacity savings and seasonal gas cost savings presented in that rate case (Docket 93-0183) in his calculations. Instead, he used a weighting based on peak day capacity and seasonal gas cost savings that he calculated using data for the period 1999-2000 through 2003-2004. IP stated that use of the same relative weighting of the Field's peak day capacity savings and seasonal gas cost savings that was presented in Docket 93-0183, when the expanded Field was placed in rate base, shows Hillsboro to be 96.8% used and useful. (Rev. IP Ex. 13.1, pp. 14-15)

Finally, Illinois Power stated that Mr. Lounsberry's "Overall Storage Concerns" provided no support for his used and useful adjustment for Hillsboro. IP stated that most of these items have been raised by Mr. Lounsberry in one or more previous dockets in support of a proposed disallowance, with no success on his part. IP further stated that all of the "overall storage concerns" are unfounded and none has any causal relationship to the reduced deliverability experienced at the Hillsboro Field or to its specific cause, the turbine injection metering error.

b. IP's Evidence That Hillsboro is Fully Used and Useful

Illinois Power noted that Staff relied on Sections 9-211 and 9-212 of the PUA as providing the criteria for including plant in rate base as “used and useful”. The text of these provisions is as follows:

The Commission, in any determination of rates or charges, shall include in a utility’s rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers. (220 ILCS 5/9-211)

No new electric generating plant or gas production facility, or significant addition to existing facilities or plant, shall be included in a utility’s rate base unless and until the utility proves, and the Commission determines, that such plant or facility is both prudent and used and useful in providing utility service to the utility’s customers. . . A generation or production facility is used and useful only if, and only to the extent that, it is necessary to meet customer demand or economically beneficial in meeting such demand. (220 ILCS 5/9-212)

It is IP’s position that in its current operating condition, the Hillsboro Storage Field satisfies these criteria. IP stated that the peak deliverability rating of Hillsboro was reduced from its “design” value of 125,000 mcf/day to 100,000 mcf per day prior to the 1999-2000 winter season, but that the rating was restored to 125,000 mcf/day prior to the 2003-2004 winter season, and this peak day deliverability rating was confirmed through a test on January 30, 2004. (Rev. IP Ex. 14.1, pp. 18-19) IP noted that Mr. Lounsberry agreed that IP is presently operating its storage fields at their rated peak day capacities. (Staff Ex. 17.0R, p. 37) IP stated that for the 2004-2005 winter season, IP injected 4.6 bcf of working gas into the Hillsboro Field, and is prepared to withdraw 4.1 bcf of working gas during this winter season to supply to customers. (Rev. IP Ex. 13.1, pp. 7, 9, 11) IP stated that at these capacities, Hillsboro is “necessary” to meet customer demand and “economically beneficial” in meeting customer demand.

With respect to the “economically beneficial” criterion, IP witness Shipp presented a calculation of the annual savings in interstate pipeline firm transportation (“FT”) charges that is produced by Hillsboro’s 125,000 mcf/day of peak deliverability (assuming that pipeline firm transportation capacity into the region served by Hillsboro could in fact be obtained to replace the entire deliverability of the Field). He also provided a calculation of the seasonal gas cost savings produced by cycling 4.1 bcf of gas, which is the amount being cycled in the 2004-2005 winter. (Rev. IP Ex. 13.1, pp. 16-17) Mr. Shipp also provided a calculation of the annual revenue requirement for the Hillsboro Field, including O&M costs, depreciation and return on the full investment at the rate of return last proposed by the Staff rate of return witness in this case, 8.25%.¹⁵

¹⁵IP noted that per the Stipulation between IP and Staff, the stipulated rate of return on rate base to be used in calculating the revenue requirement in this case is 8.18%. Based on the final stipulated rate of return of 8.18%, the Hillsboro revenue requirement is even lower than the \$7,257,000 amount calculated by Mr. Shipp. (IP Init. Br., p. 33)

(Rev. IP Ex. 13.9, p. 4) Mr. Shipp's calculations showed that at its current operating levels, the gas cost savings provided by Hillsboro substantially exceed the revenue requirement associated with including Hillsboro in rate base as 100% used and useful. Based on this comparison, IP stated that Hillsboro is "economically beneficial" in meeting IP gas customers' service demands. IP also pointed out that even if Mr. Lounsberry's calculations of the peak capacity and seasonal gas cost savings produced by the Hillsboro Field (which IP believes to be flawed and inaccurate) were used in this comparison, the revenue requirement to include Hillsboro in rate base as 100% used and useful is still less than the annual gas cost savings produced by the Field. (Rev. IP Ex. 13.9, p. 5)

IP pointed out that Staff witness Lounsberry did not present an "economic benefits" test in this case of the form presented by IP witness Shipp, and that Staff and Mr. Lounsberry did not even acknowledge the appropriateness of this test after it was presented by IP. IP noted, however, that this was the form of test that Mr. Lounsberry submitted to the Commission in a recent AmerenCIPS/AmerenUE rate case in which Mr. Lounsberry argued, successfully, that the Belle Gent storage field was no longer used and useful under Sections 9-211 and 9-212 of the PUA and should be retired. (Order in Dockets 02-0798, 03-008 & 03-009 (Cons.), October 22, 2003, pages 24-27.) IP noted the following discussion by the Commission in that order describing Staff's position:

The alternate prong of the "used and useful" test requires a utility facility to provide an economic benefit when meeting customer demand. Staff claims that the costs of Belle Gent substantially exceed the benefit ratepayers have received from the field over the past several years. In Staff's view, the storage field, therefore, does not provide an economic benefit to customers.

For its analysis, Staff measures benefits against the annual revenue requirement calculated in this proceeding of over \$67,000 for CIPS to continue operating the field. Staff also notes that over the past seven years, the only winter season in which the storage field operated was 2003. Staff asserts that Belle Gent produced a savings to ratepayers of \$17,000 for its operations in 2003, and no benefit to rate payers in the other six years. Staff suggests that the real economic cost of operations during the entire period was the product of the annual revenue requirement (\$67,000) and the period of years (7), for a total cost of \$469,000. Staff compares this figure to a total economic benefit of \$17,000 over the seven year period, and thereby concludes that the Belle Gent field also fails the "economically beneficial" prong of the "used and useful" test. (Order in Dockets 02-0798, 03-0008 & 03-0009 (Cons.), pp. 26-27)

IP emphasized that in the AmerenCIPS-AmerenUE case, Mr. Lounsberry testified that the way to determine if a storage field is used and useful is to analyze whether it is

“economically beneficial” by comparing its annual revenue requirement to the cost savings it produces for customers; whereas in this case he failed to present such an analysis and failed to acknowledge it as appropriate when it was presented by IP. (IP Init. Br., pp. 34-35)

It is also IP’s position that Hillsboro is “necessary to meet customer demand.” IP stated that at its current operating level, which was in effect for the 2003-2004 winter season as well as the 2004-2005 winter season and was confirmed by a capacity test on January 30, 2004, Hillsboro provides 125,000 mcf of peak day deliverability. The capacity of the Hillsboro Field serves the Metro East area and the Decatur area. (Rev. IP Ex. 3.19, p. 11) IP pointed out that in terms of interstate pipelines, the Metro East area is served by Natural Gas Pipeline Company of America (“NGPL”) and Mississippi River Transmission Corporation (“MRTC”), while the Decatur area is primarily served by Panhandle Eastern Pipe Line Company (“PEPL”), although it is also served by NGPL. (*Id.*) IP stated that in the current market, PEPL is fully subscribed and at least one of the mainline legs of NGPL into Illinois is fully subscribed. (*Id.*) Further, most of IP’s transmission capacity into Decatur from NGPL is utilized by retail transportation customers. (*Id.*) IP concluded that there may not be sufficient available pipeline FT capacity on NGPL and PEPL to replace the entire 125,000 mcf/day of Hillsboro capacity. (Rev. IP Ex. 13.1, p. 13) Therefore, if the Hillsboro Field did not exist, it likely would not be possible to replace its peak deliverability capacity with pipeline FT. IP noted that Staff witness Lounsberry did not dispute the fact that it might not be possible to replace the entire capacity of the Hillsboro Field by purchasing additional FT capacity from the interstate pipelines serving the area, but rather testified, “I do not know if there currently exists sufficient surplus pipeline capacity to replace the Hillsboro storage field.” (Staff Ex. 17.0R, p. 32) IP concluded that Hillsboro meets the “necessary to meet customer demand” criterion for being fully used and useful because it provides necessary peak day capability to the IP gas system and its customers that may not be obtainable from other sources (i.e., the interstate pipelines). (Rev. IP Ex. 13.9, p. 14)

c. IP’s Response to Staff Witness Lounsberry’s Used and Useful Calculation

i. Three-Year Period

IP stated that the Commission should question whether using three-year averages to determine the used and useful status of Hillsboro is appropriate for purposes of this case and whether instead only the most current information, representing the operating condition of Hillsboro and gas market conditions and prices immediately prior to the rates set in this case going into effect, should be used for any used and useful calculations. (IP Init. Br., p. 38) However, IP stated that assuming the Commission decided a three-year analysis is appropriate, the three-year period that should be used consistent with prior Commission orders is 2003-2004, 2004-2005 and 2005-2006.

IP pointed out that in his direct testimony, Mr. Lounsberry cited three prior Illinois Power rate cases in which the Commission used three year averages of IP's electric generating capacity and electric peak demand to calculate the used and useful percentage of Clinton Power Station. Those three cases were Dockets 84-0055, 87-0695 & 88-0256 (cons.) (March 30, 1989) ("Docket 84-0055"), pp. 146-147; Docket 89-0276 (June 6, 1990), pp. 78-82; and Docket 91-0147 (Feb. 11, 1992), p. 15. (Staff Ex. 7.0, pp. 29-30) Based on these three orders, Mr. Lounsberry elected to use the three years 2001-2002, 2002-2003 and 2003-2004 in his analysis. IP disagreed with Mr. Lounsberry's selection of this three-year period based on the orders he cited. IP stated that in Docket 84-0055, for which the test year was 1986 and the order was issued in March 1989, the Commission used the three years 1988, 1989 and 1990 in its used and useful calculation. In Docket 89-0276, for which the test year was 1990 and the order was issued in June 1990, the Commission used the three years 1989, 1990 and 1991. In Docket 91-0147, in which the test year was 1992 and the order was issued in February 1992, the Commission looked at several three-year periods in making its used and useful determination: 1991-1993, 1992-1994 and 1993-1995. IP stated that a consistent thread among these three cases is that the three-year period the Commission used consisted of the year prior to the year of the order, the year in which the order was issued (i.e., the year in which the new rates went into effect) and the year following the order. (IP Init. Br., pp. 38-39) IP stated that applying the same approach to the circumstances of this case, the three years that should be used are 2003-2004, 2004-2005 (2005 being the year the new rates go into effect) and 2005-2006. (Rev. IP Ex. 13.1, p. 10) IP pointed out that in none of the three cases relied on by Mr. Lounsberry did the Commission use a three-year period that completely preceded the order date, as Mr. Lounsberry did here. Further, in none of these cases did the Commission use three years of completely historic data as Mr. Lounsberry did here. (IP Init. Br., p. 39)

IP further noted that in his rebuttal testimony, Mr. Lounsberry stated "I agree that generally the Commission dealt with the used and useful issue for the Clinton nuclear plant using the three-year period discussed by [IP witness] Mr. Shipp", but he then cited another prior Commission order, *Commonwealth Edison Company*, Docket Nos. 87-0427/87-0169/88-0219/88-0253/90-0169 (cons.), Revised Order on Remand (Feb. 24, 1993) ("*ComEd*"), in which, he asserted, "the Commission made use of a three-year period that centered on the test year." (Staff Ex. 17.0R, p. 28) However, IP indicated that the order in *ComEd* shows that in that case the Commission also essentially used a three-year period consisting of the year before the order, the year of the order and the year after the order. IP explained that although *ComEd* comprised a number of dockets that had been consolidated, the used and useful determination was made in the context of a rate case, Docket 90-0169, that had been originally filed in April 1990. (*ComEd* Order, p. 4) The original order was issued on March 8, 1991, and used a 1991 test year. (*Id.*, pp. 1, 4) In an appeal by intervenors from the March 8, 1991 Order, the Supreme Court ruled that the Commission had misapprehended the meaning of Section 9-215 of the PUA (a statute applicable only to electric generating plants) in determining

what used and useful test it could apply to certain of the utility's generating plants.¹⁶ The case was therefore remanded to the Commission to reconsider its used and useful determination. On remand, consistent with the Supreme Court decision, the Commission used a three-year load and capacity analysis (as it had in the three earlier IP cases). However, the Commission recognized that it could not update the original record for more recent information but rather had to use the load and capacity data in the original record, which was for the three years 1990, 1991 and 1992. (*ComEd* Order, p. 4) As a result, in the *ComEd* Order, although it was issued in 1993, the Commission essentially "redid" the used and useful analysis in its original 1991 order using data from the year before the order, the year of the order and the year following the order. IP concluded that, in the context of this case, the approach followed in *ComEd* supports using the three-year period 2003-2004, 2004-2005 and 2005-2006, *not* three completely historic years as employed by Mr. Lounsberry. (IP Init. Br., p. 40)

However, Illinois Power also pointed out that in a subsequent order issued after the four orders relied on by Mr. Lounsberry, the Commission specifically addressed the question of which three-year period to use in a used and useful analysis, and adopted the position advocated here by IP while rejecting the position advocated by Mr. Lounsberry. *Commonwealth Edison Company*, Docket 94-0065 (Jan. 9, 1995), 158 P.U.R. 4th 458, 1995 WL 45969. In resolving a disputed issue as to which three-year period to use for the used and useful test, the Commission stated:

While the remaining parties are in agreement on the used and useful methodology, there is substantial disagreement with respect to the various components of the needs test. The first issue on which they disagree is the period during which the units' used and useful status is determined. Edison proposes a three-year period of 1994-1996, centered on the year rates will take effect; Staff and CUB propose a three-year test period of 1993-1995 centered on the test year; and the City proposes use of the test year only. In the Remand Order the Commission indicated its preference for a three-year period rather than the one-year test year for the needs determination. All five of the Commission's past decisions establishing three-year used and useful periods centered their used and useful periods on a year in which the rates to be charged were to be in effect. The Commission has not required that the three year period be centered on the test year. See *Illinois Power Company*, Docket 84-0055 et al., p. 146. The Commission continues to believe that the three-year averaging process is appropriate, and finds that Edison's proposed 1994-1996 period, which is centered on the year the rates determined in this proceeding will take effect, is the appropriate test period and is consistent with past decisions of the Commission. The Commission believes it is reasonable to employ a used and useful test period that provides a more

¹⁶*Business & Professional People for the Public Interest v. Commerce Commission*, 146 Ill. 2d 175 (1991). In its original March 1991 order, the Commission had not used a three-year load and capacity analysis in making its used and useful determination.

prospective view of whether Byron Unit 2 and Braidwood Units 1 and 2 are used and useful. (emphasis supplied)

IP stated that the Commission's resolution of this issue in Docket 94-0065, in which it took into account the prior orders relied on by Mr. Lounsberry, requires that the three-year period he advocates be rejected and that the three-year period that IP employed in its re-do of Mr. Lounsberry's calculations should be adopted. IP stated that Mr. Lounsberry's three-year period centers on the historic test year while the three-year period used by IP witness Mr. Shipp centers on the year the rates approved in this case will go into effect, i.e., the year of the rate order. (IP Init. Br., p. 41)

IP stated that the decision as to which three-year period to use in this case is not merely an academic exercise. IP pointed out that in two of the three years Mr. Lounsberry used, Hillsboro was rated at 100,000 mcf/day peak deliverability, whereas in each of the three years 2003-2004, 2004-2005 and 2005-2006, Hillsboro is rated at its full 125,000 mcf/day peak deliverability, which Mr. Lounsberry agreed is the rating at which Hillsboro is now operating. Thus, Mr. Lounsberry's selection of a three-year period results in a lower used and useful percentage in his calculation. IP stated that regardless of the period selected for the calculations, a peak deliverability rating of 125,000 mcf/day should be used in the used and useful calculation, since the rating of the Hillsboro Field was restored to that value prior to the 2003-2004 winter season and the 125,000 mcf/day rating has been confirmed by testing. (Rev. IP Ex. 13.1, p. 11; IP Init. Br., pp. 41-42) IP also pointed out that with respect to the seasonal gas cost component of Mr. Lounsberry's analysis, the annual average amount of gas cycled from the Field in the three-year period he selected was lower than the annual average amount of gas cycled or to be cycled in 2003-2004, 2004-2005 and 2005-2006. IP emphasized that with the respect to the seasonal gas savings calculation as well as the peak capacity savings calculation, Mr. Lounsberry's selection of an inappropriate three-year period drove down his calculated used and useful percentage. (IP Init. Br., p. 42)

ii. Value of Peak Day Capacity

IP argued that Staff witness Lounsberry's calculation of the peak day capacity cost savings benefit produced by Hillsboro was flawed in several respects. IP noted that Mr. Lounsberry used a price taken from just one of IP's current pipeline FT contracts for the cost of replacement pipeline FT capacity, the rate in IP's contract associated with the NGPL Metro East Lateral.¹⁷ (Rev. IP Ex. 13.1, p. 12)

IP stated that Mr. Lounsberry's use of a single FT rate from a single year (2003) was inconsistent with his own approach of using a three-year average for his used and useful calculations, as well as with his use of five years of historical data to calculate the seasonal gas cost savings. IP noted that in light of Mr. Lounsberry's statement in his

¹⁷IP noted that Mr. Lounsberry obtained the FT price he used from IP's response to a data request in its PGA reconciliation case for 2003, Docket 03-0699. (See Staff Ex. 7.0, p. 27 and Schedule 7.05)

testimony that the cost of peak day transportation capacity has been declining over time (Staff Ex. 17.0R, p. 35), his internally inconsistent use of just a single, recent pipeline FT rate had the effect of driving down the value of Hillsboro's peak deliverability. IP pointed out that Hillsboro's expected peak deliverability was reduced for several years, but only to 80% of its design value (i.e., 100,000 mcf/day vs. 125,000 mcf/day). In contrast, in the three years selected by Mr. Lounsberry only about 34% to 36% of the maximum working gas inventory of 7.6 bcf was cycled. (Staff Sched. 7.04) IP contended that under the methodology Mr. Lounsberry employed, by driving down the value of Hillsboro's peak deliverability savings benefit relative to the seasonal gas cost savings, he could calculate a lower "weighting" for the peak capacity benefit (an area in which Hillsboro has performed closer to its design value) and a greater weighting for Hillsboro's seasonal gas savings benefit (an area in which Hillsboro's performance has been farther from its design value), thereby producing a lower overall used and useful percentage. IP concluded that Mr. Lounsberry's selection of the pipeline FT price he used enabled him to calculate a low used and useful percentage for Hillsboro. (IP Init. Br., p. 43)

More significantly, IP pointed out that the FT price Mr. Lounsberry elected to use was for transportation on an NGPL lateral that runs only from Centralia, Illinois to the Metro East area, entirely within the IP service area. It is not a long-haul contract and does not include the cost of firm pipeline transportation from the gas producing fields to the IP service area. IP stated that this contract falls far short of representing the full cost to replace Hillsboro's peak day capacity with pipeline FT. (Rev. IP Ex. 13.9, p. 10) IP stated that in contrast, the pipeline FT costs that IP witness Shipp used in re-doing Mr. Lounsberry's calculations were representative of the full costs of pipeline FT from the gas producing fields in the Mid-continent area (Texas-Oklahoma-Kansas) and the Gulf Coast area (Texas-Louisiana) to IP's service area. (*Id.*) As a result, the pipeline FT costs that Mr. Shipp used, and the resultant peak day capacity cost savings benefit he calculated, were considerably higher than those calculated by Mr. Lounsberry. The peak day capacity cost savings benefit that Mr. Shipp calculated, using complete pipeline FT costs, exceeded the peak day capacity cost savings benefit that Mr. Lounsberry calculated by more than 2.5 times. (See Rev. IP Ex. 13.1, p. 12)

IP responded to Staff's argument that the peak day capacity value Mr. Lounsberry used in this case compared favorably to an estimate of the annual value of a 25,000 mcf/day increment of capacity on IP's system that Mr. Lounsberry presented in another case. IP stated that although Staff characterized the value from the earlier case as an "annual value", in fact it was based on a short-term, three-month contract. (Rev. IP Ex. 13.9, p. 14) IP stated that the contract was from IP's PGA case for 2001 (Docket 01-0701), but that pipeline FT prices are much higher today than in 2001 because the pipelines are fully or nearly fully subscribed, a fact that Staff does not attempt to refute. (Rev. IP Ex. 13.9, pp. 11-12, 14) IP also pointed out that in Docket 01-0701, Mr. Lounsberry recommended a prudence disallowance based on IP's reduction of the peak deliverability rating of its Shanghai Storage Field by 25,000 mcf/day; however, the Commission rejected Mr. Lounsberry's recommendation and found that IP had acted prudently in reducing the peak day rating of Shanghai. (Order in Docket 01-0701 (Feb.

19, 2004), pp. 7, 25) Because the Commission rejected Mr. Lounsberry's proposed prudence disallowance on its merits, the Commission never passed on his estimate of the additional pipeline costs IP had incurred due to the Shanghai deliverability reduction, i.e., on his estimate of the value of a 25,000 mcf/day increment of capacity on IP's system. IP stated that as a result, Mr. Lounsberry's estimate from Docket 01-0701 remained nothing more than an untested assertion he made in a prior case. IP concluded that Mr. Lounsberry has done nothing more than attempt to bolster the peak day capacity value he used in this case by citing his own untested and unapproved prior testimony from an earlier case. (IP Rep. Br., p. 50)

IP argued that another flaw in Mr. Lounsberry's analysis was that he failed to recognize that the Hillsboro Field serves two distinct areas, the Metro East area and the Decatur area, which are served principally by different interstate pipelines (NGPL and PEPL, respectively). (Rev. IP Ex. 13.1, p. 12, Rev. IP Ex. 13.9, p. 11) IP stated that it would not be possible to replace all of the capacity of the Hillsboro Field with NGPL capacity, assuming that much capacity were in fact available on NGPL, and still serve the geographic areas of IP's service area that are served using the peak day capability of the Hillsboro Field. (Rev. IP Ex. 13.9, p. 11) Thus, to replace Hillsboro's capacity would necessitate the acquisition of additional FT capacity on both NGPL and PEPL.¹⁸ Therefore, IP witness Mr. Shipp, in re-doing Mr. Lounsberry's used and useful calculations, used an average of the prices from IP's most recent FT contracts negotiated with NGPL and PEPL. The amount of these contracts aggregated to approximately the amount of FT capacity that would be needed to replace Hillsboro's peak day capacity. (Rev. IP Ex. 13.1, p. 12)

Finally, IP argued that Mr. Lounsberry erroneously asserted that if IP were to replace the entire capacity of the Hillsboro Field with pipeline FT, IP should be able to obtain greater discounts from the prices it currently pays for pipeline FT capacity. IP stated that Mr. Lounsberry's contention displayed a lack of appreciation of current market realities. IP stated that PEPL is fully subscribed and at least one of the NGPL mainline legs into Illinois is fully subscribed. As a result, IP stated, these pipelines basically have no reason to give significant discounts in order to sell large blocks of incremental FT capacity (i.e., capacity above and beyond the historic capacity levels already held by IP) under current capacity market conditions. IP concluded that in light of the existing pipeline capacity markets in the Midwest, IP would expect to pay higher prices, not lower prices, for large blocks of incremental FT capacity. (Rev. IP Ex. 13.9, p. 12)

IP responded to Mr. Lounsberry's contention that his position that IP could achieve larger discounts if purchasing large blocks of incremental FT capacity was supported by testimony of an Ameren witness in Docket 04-0294 concerning "buying power" savings in IP's purchased gas costs as a result of the Ameren acquisition. (Staff

¹⁸IP noted that although NGPL also serves the Decatur area, virtually all of IP's transmission capacity into the Decatur area from NGPL is already used by transportation customers. (Rev. IP Ex. 13.9, p. 11)

Ex. 17.0R, p. 31) IP stated that Mr. Lounsberry cited that testimony out of context. IP stated that while the Ameren witness testified that IP should be able to get larger discounts in the future negotiating as part of Ameren than it could have obtained standing alone, he did not testify that IP would be able to obtain larger discounts in the future as a part of Ameren than IP had obtained in the past as a stand-alone company under significantly different market conditions. Rather, the Ameren witness made it clear that future pipeline discount levels will vary over time based on market conditions. (Rev. IP Ex. 13.9, p. 13)

iii. Seasonal Gas Cost Savings

IP took issue with Staff witness Lounsberry's calculation of the seasonal gas cost savings benefit of Hillsboro. Mr. Lounsberry used the difference between IP's cost of gas in storage and the cost of spot gas purchased by IP over the five year historical period 1999-2000 through 2003-2004. IP contended that this use of five years of historic data was flawed. IP pointed out that Mr. Lounsberry himself emphasized that gas markets are not static and that "many changes have occurred over the past ten years." (Staff Ex. 17.0R, p. 35) IP witness Shipp testified that to accept Mr. Lounsberry's calculation of the seasonal gas cost savings to be expected from the Hillsboro Field, the Commission would have to assume that IP bought gas for injection during the 2004 injection season at the same prices it purchased gas for injection in 1999, 2000 and 2001, and that it will be able to buy spot commodity gas during the 2004-2005 winter at the same prices for which gas was purchased in the 1999-2000, 2000-2001 and 2001-2002 winter seasons. He testified that over the period that Mr. Lounsberry used for his seasonal gas cost savings calculation, the gas markets have in fact changed significantly. Mr. Shipp pointed out that due to the relatively recent installation of almost 200,000 mW of gas-fired electric generation in the U.S. which has increased the demand for gas during the summer, there are now periods in which gas prices in the winter heating season are not significantly different than prices in the summer. In fact, at times during the summer injection season, commodity gas prices can be higher than in the winter season.

IP concluded that the realities of recent and current market pricing are not reflected in the five-year historical data that Mr. Lounsberry used. (Rev. IP Ex. 13.9, p. 9) IP also noted that Mr. Lounsberry's use of a five-year period to develop the seasonal gas cost savings was inconsistent with his overall use of the three-year period for the used and useful analysis. (Rev. IP Ex. 13.9, p. 15) IP again pointed out that Mr. Lounsberry's use of five years of historical data rather than current market pricing to develop the seasonal gas cost savings appears to have been results-driven, because under his methodology, by calculating a higher seasonal gas cost savings benefit for Hillsboro, Mr. Lounsberry could then calculate a higher weighting for the seasonal gas cost benefit relative to the peak day capacity benefit, and thereby produce a lower used and useful percentage.

IP witness Shipp testified that the appropriate comparison to calculate Hillsboro's seasonal gas cost savings benefit would be to compare the cost of gas when it is injected into the Field to the spot price of gas at the time of withdrawal, utilizing futures

prices, not historical prices. In re-doing Mr. Lounsberry's calculations, Mr. Shipp used a comparison between New York Mercantile Exchange ("NYMEX") prices for (i) gas deliveries in the April 2005 to October 2005 period and (ii) gas deliveries in the November 2005 to March 2006 period. These are prices quoted on the NYMEX for contracts for delivery of gas in those months. (Rev. IP Ex. 13.1, pp. 13-14; Rev. IP Ex. 13.9, p. 15) Mr. Shipp explained that current gas futures prices on the NYMEX are a much more reliable indicator of spot commodity gas prices since they represent actual commodity price positions taken by market participants based upon current gas market fundamentals. (*Id.*, p. 9) The NYMEX gas futures market is recognized as the primary tool for price discovery by the entire gas industry, and, the NYMEX contracts are actual price positions based upon current and future market conditions and industry fundamentals. Mr. Shipp stated that the NYMEX is the most accurate representation of future price differentials under current market conditions between gas commodity purchased during the summer injection season and gas purchased during the winter heating season, which is the basis of the seasonal gas cost savings provided by storage fields. (*Id.*, pp. 15-16) IP concluded that consistent with the proposition that the determination of whether the Hillsboro Field is used and useful for the purpose of setting rates that will go into effect in May 2005 and be in force thereafter should be based on the current and reasonably foreseeable operating status of the Field, NYMEX gas futures prices, rather than five-year old price data, should be used to calculate the seasonal gas cost savings benefit that Hillsboro produces. (IP Init. Br., p. 47)

IP stated that there is another problematic aspect of the seasonal gas cost portion of Mr. Lounsberry's used and useful calculation. IP stated that in calculating the Hillsboro used and useful percentage, Mr. Lounsberry took the amount of gas cycled in each of the three years 2001-2002 through 2003-2004 as a percent of 7.6 bcf, the maximum "design" working gas inventory of the Field. (See Staff Schedule 7.04) His approach assumes that the entire 7.6 bcf working gas inventory should be withdrawn from the Field each winter season to be supplied to customers. IP stated that this is an unrealistic assumption, because the entire amount of working gas inventory in a storage field will not necessarily be withdrawn in every year. IP would expect to cycle the full inventory of working gas in its fields each winter season assuming normal weather and no other abnormal changes in load. However, if winter weather is warmer than normal or there is an unexpected drop in load (particularly in the second half of the withdrawal season), the full working gas inventory may not be withdrawn. IP also pointed out that storage fields can experience temporary fluctuations in the amount of working gas that can be cycled, due to operational issues that arise as a result of the nature of storage field operations. Therefore, IP concluded, it is not realistic to assume that the entire working gas inventory of a particular storage field would be cycled every year. (Rev. IP Ex. 13.1, p. 8) IP stated that Mr. Lounsberry did not dispute this point. (IP Init. Br., p. 48) IP pointed out under Mr. Lounsberry's methodology Hillsboro would have to be rated at its full peak deliverability capacity of 125,000 mcf/day and cycle its maximum design capacity of 7.6 bcf in each year of the three-year period in order for his methodology to show the Field to be 100% used and useful. IP indicated that under Mr. Lounsberry's methodology, even if the amount of working gas cycled from Hillsboro were consistently 95% of the maximum of 7.6 bcf (whether due to warmer weather, load

fluctuations or other reasons), his calculations would show Hillsboro to be less than 100% used and useful. IP stated that Mr. Lounsberry's used and useful test is unreasonably stringent and inconsistent with operating realities because his methodology requires perfection in order for Hillsboro to be 100% used and useful. IP stated that the Commission has not required perfection from Illinois gas utilities in the operation of their storage fields. IP pointed out that in a recent PGA reconciliation case in which Mr. Lounsberry recommended a disallowance relating to another IP storage field, which the Commission rejected, the Commission stated that "a natural gas aquifer storage field is a complex physical system." (Order, Docket 01-0701 (Feb. 19, 2004), p. 25). (IP Init. Br., pp. 48-49)

iv. IP's Recalculation of Mr. Lounsberry's Used and Useful Calculation

Illinois Power witness Shipp recalculated the Hillsboro used and useful percentage using Mr. Lounsberry's methodology but (i) using the three years 2003-2004, 2004-2005 and 2005-2006 rather than the earlier three year period used by Mr. Lounsberry; (ii) using the full 125,000 mcf/day peak deliverability rating of Hillsboro for each of the three years (which in fact was the case), (iii) using as the replacement pipeline FT price the average of the prices paid to NGPL and PEPL in IP's most recently negotiated contracts with these pipelines, and (iv) using NYMEX futures contracts prices for the summer injection and winter withdrawal seasons to develop the seasonal price differential, rather than historical prices that were as much as five years old, as employed by Mr. Lounsberry. Using these parameters and inputs, Mr. Shipp calculated an 84.33% used and useful percentage for Hillsboro, in contrast to the 54.33% used and useful percentage that Mr. Lounsberry had calculated. (Rev. IP Ex. 13.1, p. 14)

IP pointed out that Mr. Shipp's calculations generated a weighting for the peak day savings benefit of 66.24% and a weighting for the seasonal gas cost savings benefit of 33.76% (*Id.*), which was almost the complete reverse of the respective weightings (35.83% and 64.17%) generated by Mr. Lounsberry. (See Staff Sched. 17.01) IP noted that with the higher relative weighting for the peak day savings benefit and the better relative performance by the Hillsboro Field with respect to peak day deliverability as opposed to annual working gas inventory cycling, Mr. Shipp calculated a used and useful percentage considerably higher than the percentage Staff witness Lounsberry calculated. IP stated that this comparison demonstrated how though his choices of the three-year period, the price of replacement FT capacity and the five-year historic gas prices he used, Mr. Lounsberry generated an inaccurately low used and useful percentage. IP concluded that its inputs and resulting calculations are much more representative of the current and foreseeable operating status of the Hillsboro Storage Field and of the industry and market conditions in which it will be operating when the rates established in this proceeding go into effect. (IP Init. Br., pp. 49-50)

v. Used and Useful Calculation Using Weightings of Peak Capacity Savings and Seasonal Gas Cost

Savings Based on the Relative Benefits Expected from Hillsboro in Docket 93-0183

IP stated that the entire premise for Staff witness Lounsberry's proposed used and useful adjustment was that the expanded Hillsboro Field has not provided the peak day deliverability and annual working gas volume that was planned when the investment in the expanded Field was placed in rate base in Docket 93-0183. IP pointed out that in Docket 93-0183, the rate case in which the investment in the expanded Hillsboro Field was placed in rate base, IP presented a calculation of the value of the peak day savings benefits and seasonal gas cost savings benefits expected from the expanded Field. IP stated that consistent with Mr. Lounsberry's underlying rationale, his calculation of whether and to what extent Hillsboro is used and useful should have been based on the relative weightings of the peak day savings and seasonal gas cost savings benefits presented to the Commission in Docket 93-0183. (Rev. IP Ex. 13.1, p. 14-15; Rev. IP Ex. 13.9, p. 3) As Mr. Lounsberry pointed out in his direct testimony, in Docket 93-0183 IP represented to the Commission that the expanded Hillsboro Field was projected to produce annual savings of \$13,599,000 in reduced pipeline charges and \$997,500 due to increased seasonal gas purchases. (Staff Ex. 7.0, p. 26, quoting Order in Docket 93-0183, p. 26) Thus, 93% of the savings from the Hillsboro expansion were from the Field's increased peak day deliverability while 7% of the savings were from increased seasonal gas purchases. IP stated that if these percentages are inserted into Mr. Lounsberry's used and useful calculation with no other changes to his calculations, the result of his calculations would be that Hillsboro is 85% used and useful, not 53% as calculated by Mr. Lounsberry. Further, if his calculations were based on the three-year period 2003-2004 through 2005-2006, meaning that 125,000 mcf/day is used as the Field's actual peak day capacity for all three years and the amount of gas cycled on average for the three years is 53.58% of the 7.6 bcf maximum, then Mr. Lounsberry's calculations would show Hillsboro to be 96.8% used and useful. (Rev. IP Ex. 13.1, p. 15)

IP also stated that the comparison of Mr. Lounsberry's weighting of the Hillsboro benefits to the weighting of the benefits indicated in Docket 93-0183 showed that his methodology is not simply measuring the impact of Hillsboro's below-design level performance during the years he analyzed, but it is also measuring changes in the overall economics of the gas and pipeline markets subsequent to 1993. IP noted that Mr. Lounsberry himself testified, "it is obvious that many changes have occurred [in the natural gas industry] over the last ten years, including the apparent reduction to the cost of peak day transportation capacity." (Staff Ex. 17.0R, p. 35) IP stated that Mr. Lounsberry's used and useful was measuring not just Hillsboro's operating condition, but also changing economics in the gas markets that impact the cost savings produced by the Field, even when operating at its full design parameters.

d. IP's Response to Staff Witness Lounsberry's Overall Storage Concerns

It is Illinois Power's position that the "overall storage concerns" Mr. Lounsberry identified provide no support for his proposed used and useful adjustment to Hillsboro. IP stated that the deliverability decline at the Hillsboro Storage Field was caused by a measurement error in the plant injection meters which resulted in IP injecting less gas into the Field than it believed it was injecting based on the plant meter readings. IP also contended that it was extremely proactive, worked diligently over a period of years, pursued several avenues of investigation and expended considerable resources, in attempting to find the cause of the deliverability declines. (Rev. IP Ex. 13.1, p. 19; see Rev. IP Ex. 14.1, pp. 4-16) IP argued that Mr. Lounsberry failed to show any connection between any of his "overall storage concerns" and the deliverability decline at the Hillsboro Field, and that in fact there is no such connection. (Rev. IP Ex. 13.9, pp. 16-17) IP also stated that Mr. Lounsberry previously raised a number of these same issues, including his issues relating to "Reductions in Peak Day Capacity", "Manpower", "Capital Expenditures" and "Hillsboro Incident", in at least one and in some cases two previous annual PGA reconciliation cases before the Commission. IP stated that it has already responded to these issues through discovery responses and testimony filed in those cases. In one of those cases, Docket 01-0701 (the PGA reconciliation case for 2001), Mr. Lounsberry cited a number of these issues as support for a proposed gas cost imprudence disallowance; however, the Commission rejected Mr. Lounsberry's recommendations and did not impose any imprudence disallowance based on any of these issues. (Rev. IP Ex. 13.1, pp. 17-18)

IP responded specifically to each of Staff witness Lounsberry's "overall storage concerns, as summarized below.

i. Reduction in Peak Day Capacity

IP responded to Mr. Lounsberry's "overall storage concern" that in recent years, IP has reduced the peak deliverability ratings on two of its storage fields, Hillsboro and Shanghai. IP pointed out that Mr. Lounsberry acknowledged that "IP, at the present time, is operating its storage fields at their rated peak day capacities." (Staff Ex. 17.0R, p. 37) Additionally, Shanghai was de-rated for only one winter season, 2001-2002, before being restored to its original rating for the 2002-2003 winter, which it has maintained thereafter. (Rev. IP Ex. 13.1, pp. 21-22) IP also pointed out that Mr. Lounsberry recommended a gas cost disallowance due to the Shanghai rating reduction in Docket 01-0701 (IP's 2001 PGA reconciliation case), but the Commission reached the following conclusion after considering all of Mr. Lounsberry's arguments and IP's responses:

In light of the foregoing, the Commission is persuaded by IP that IP acted reasonably and prudently with regard to its decision to reduce the peak day deliverability of Shanghai by 25,000 Mcf/d for purposes of its 2001 PGA reconciliation. While certain errors occurred and hindsight shows that some of IP's observations and beliefs were incorrect, a natural gas aquifer storage field is a complex physical system and the Commission

finds that under the circumstances IP's actions with respect to Shanghai were not imprudent. (Order, Docket 01-0701 (Feb. 19, 2004), p. 25))

IP also noted that the record showed that deliverability decline has been reported to be the most common problem in the gas storage industry. IP witness Hower cited U.S. Department of Energy publications that indicate, based on more than 350 U.S. storage reservoirs, that most gas storage operators experience a decline in deliverability over time. He testified that "This does not sound like an isolated problem, or one common only to Illinois Power. . . [Mr. Lounsberry's] observations regarding reductions in peak day capacity and declines in deliverability for gas storage reservoirs are not at all consistent with the experience of the overall gas storage industry." (IP Ex. 17.1, pp. 18-19) IP further noted that in his rebuttal testimony, Mr. Lounsberry stated, "I also agree with Mr. Hower that storage well and field deliverability declines are not uncommon in the industry." (Staff Ex. 17.0R, p. 37)

Finally, IP responded to Staff's contention that the temporary peak day capacity reductions at Hillsboro and Shanghai "occurred in large part due to the manner that the Company operates, reviews and oversees its storage operations and its ability, or inability, to properly conduct root cause analysis of problems at its storage fields. (Staff Init. Br., p. 38) IP pointed out that neither Mr. Lounsberry's testimony nor Staff's brief demonstrated any causal connection between any of the areas of storage field management about which Mr. Lounsberry expressed concern and the temporary peak capacity reductions at Shanghai and Hillsboro. (IP Rep. Br., p. 58)

ii. Manpower

IP responded to another of Mr. Lounsberry's "overall storage concerns" that over the period from 1991 to 2000, IP reduced the number of supervisors at its storage fields from four to one. IP pointed out that Mr. Lounsberry also acknowledged that "the number of storage field operators has remained stable since 1991." (Staff Ex. 7.0, p. 35) IP witness Mr. Shipp explained how IP reorganized its work force in a manner that permitted the reduction in storage field supervisors. He noted that while reducing the number of supervisors, IP also upgraded one of the operator positions at each storage field to foreman. He pointed out that the storage field operators have more than 240 years of total gas storage experience and continue to increase their level of expertise through various training and educational programs. He further noted that IP also has a manager of storage who oversees all of the storage fields. (IP Ex. 13.1, pp. 20-21)

IP argued that while Mr. Lounsberry asserted that the reduction in number of supervisors has resulted in IP conducting poor root cause analysis (an assertion IP also disputed), he failed to support his assertion with any specifics. IP also noted that Mr. Lounsberry showed no connection between the Hillsboro deliverability decline and the reduction in the number of IP storage field supervisors. Further, IP stated that Mr. Lounsberry failed to recognize that IP also maintains a "headquarters" staff of engineering personnel who are engaged in the investigation of issues such as the Hillsboro deliverability decline; and that IP obtains outside resources (such as Mr.

Hower and his firm) when needed to assist in such investigations and analyses. IP witnesses Hood and Kempainen, who are part of IP's headquarters staff, testified:

We have been involved in the investigation, discovery and remediation of the specific problem that led to the temporarily reduced capacity at the Hillsboro Storage Field that is the basis for Mr. Lounsberry's proposed used and useful adjustment, namely, the error in the turbine injection metering due to the operation of the compressors at certain loadings. Based on our involvement, we do not believe there is any connection between the reduction in the number of storage field supervisors and this problem or the time it took to discover the problem. Nor has Mr. Lounsberry identified any linkage. To the contrary, as we and Mr. Hower detailed in our rebuttal testimonies, Illinois Power diligently investigated the source of the declining performance at the Hillsboro Field over a number of years until it identified and corrected the problem. These efforts were not hampered by a lack of supervisory resources or a lack of any other resources. Similarly, there is no causal connection to support Mr. Lounsberry's assertion in the "Conclusion" to the "Overall Storage Concerns" section of his rebuttal testimony (lines 1011-1012) that "After reducing its manpower levels, IP's ability to identify and act upon problems at its storage fields declined." (IP Ex. 14.3, pp. 13-14)

iii. Capital Expenditures

IP responded to Mr. Lounsberry's "overall storage concern" that IP's budgeted capital expenditures for its storage fields were lower in recent years (2002-2004) than in earlier years (2000-2001), that he was concerned that IP was not being proactive in making upgrades to its storage fields, and that IP was unwilling to make capital expenditures since the costs are not recoverable through the PGA. IP noted that Staff admitted that it was not in possession of detailed information about IP's capital budgeting procedures for its storage field operations. IP disputed Staff's assertions and stated that the record showed that IP in fact has been proactive in identifying and correcting problems at all of its storage fields, and has initiated numerous projects to avoid potential problems while trying to ensure maximum deliverability ratings. (IP Rep. Br., pp. 59-60)

IP witness Shipp, IP's Director of Gas Supply, explained that IP plans for capital improvements for its storage fields on a rolling five year basis and that "I do not believe that any capital projects that were viewed as necessary or desirable within a five year plan have been omitted due to lack of adequate capital budget." (Rev. IP Ex. 13.1, p. 23) He stated that "I have been in my present position through four budgeting cycles and in my tenure the storage fields have never had a requested project rejected by management due to capital budget limitations." (*Id.*) Mr. Shipp presented a detailed list of the projects and enhancements that Illinois Power has implemented at all of its storage fields over the period 1995-2003, and a detailed list of all the studies that IP performed on its storage fields during the period 1998-2003. (IP Ex. 13.6-13.7) He

pointed out that Mr. Lounsberry failed to identify any storage field projects that IP should have implemented but has not. (Rev. IP Ex. 13.1, pp. 23-24) Finally, Mr. Shipp explained that in determining whether to undertake discretionary capital projects (i.e., projects that are not necessary due to regulatory or safety requirements, to support new customer business (demand) or to replace failed or obsolete equipment), IP evaluates whether the project will result in a lower overall cost of service, not just on whether or not the costs of the project will impact the PGA. (Rev. IP Ex. 13.9, p. 17) IP noted that the extensive list of capital projects presented by Mr. Shipp for the period 1995-2003 were not expenditures IP could have recovered through the PGA but rather expenditures it would have to wait till its next rate case to begin recovering. (IP Rep. Br., p. 60)

IP also pointed out that Mr. Lounsberry's basic concern that "IP's capital expenditure levels have been reduced over the same time period that the Company experienced problems at its two largest storage fields" (Staff Init. Br., p. 41) is misplaced as a matter of time. IP noted that Mr. Lounsberry's observation was that the capital expenditure amounts for the years 2002-2004 were significantly lower than for 2000 or 2001, and more generally, lower than over the period 1995-2001. (*Id.*, p. 40) However, the record in this case shows that the problems at the Hillsboro Field (i.e., the turbine injection metering error) occurred over the period 1993-1999; and that Shanghai's capacity reduction occurred in 2001. Moreover, the summary of Staff's evidence relating to the Shanghai peak capacity reduction in the Commission's Order in Docket 01-0701 shows that the IP management actions and decisions that Staff contended (unsuccessfully) led to the peak capacity reduction for 2001 occurred over a period from the mid-1990s to 2000, again a period in which Mr. Lounsberry apparently believes the levels of IP's storage field capital expenditures were adequate. (See Order in Docket 01-0701, pp. 8-11) Thus, the "problems" at the two storage fields actually occurred during the period of higher capital expenditures that Mr. Lounsberry held up as the baseline. (IP Rep. Br., pp. 60-61)

IP argued that, similar to his concern about the number of supervisors at the storage fields, Mr. Lounsberry failed to show any connection between IP's level of capital spending for its storage fields and the specific Hillsboro deliverability decline or IP's ability to resolve that problem. (IP Init. Br., p. 58) IP witnesses Hood and Kemppainen testified:

The turbine metering injection error and the failure to discover the error sooner did not result from the failure to undertake any particular capital projects or from the level of capital expenditures generally. As we and Mr. Hower have described in our rebuttal testimonies, Illinois Power devoted considerable internal and external resources to determining the source of the Hillsboro performance decline that is the basis for Mr. Lounsberry's proposed used and useful adjustment. (IP Ex. 14.3, p. 14)

iv. December 2000 Hillsboro Incident

IP responded to Mr. Lounsberry's concern that IP failed to conduct an adequate root cause analysis in connection with a December 2000 incident at the Hillsboro Field in which a produced water tank became overpressurized and was launched from its foundation, resulting in damage to other structures and equipment and an outage at the Field. IP pointed out that this incident has been a topic in several previous dockets including Docket 00-0714 and Docket 01-0701. IP made the following points concerning its investigation of and response to the December 2000 incident:

- (1) Promptly following the December 2000 incident, IP hired a qualified outside engineering firm, Packer Engineering, to conduct an investigation of the incident and submit a report, which Packer did. Mr. Lounsberry did not question Packer's qualifications to carry out this assignment. (Rev. IP Ex. 14.1, p. 28; Staff Ex. 7.0, pp. 40-41; Staff Ex. 17.0R, p. 44; IP Ex. 14.3, p. 15))
- (2) The Commission's Office of Pipeline Safety ("OPS") conducted a thorough, independent investigation of the December 2000 Hillsboro incident and issued a report on it, but did not make any findings of violations or non-compliances by IP. (Rev. IP Ex. 13.1, p. 18; Rev. IP Ex. 14.1, p. 33; see IP Ex. 14.4)
- (3) The OPS Report itself reached no conclusion as to what was the root cause of the December 2000 incident. (Rev. IP Ex. 14.1, p. 31)
- (4) The OPS report (which was completed almost ten months after the December 2000 incident) did not question the quality of IP's investigation of the incident, and OPS has never expressed any concerns to IP on this topic through other means. (IP Ex. 14.3, p. 16)

IP stated that, most importantly, it implemented a number of corrective actions pertaining to the equipment involved in the incident and its operation, some of which were based on Packer Engineering's recommendations, to attempt to prevent a repeat of the incident. (Rev. IP Exhibit 14.1, pp. 31-32) Mr. Lounsberry did not criticize as insufficient, incomplete or inappropriate any of the corrective actions that IP implemented in response to the December 2000 incident, which were itemized in the record. IP also noted that the Commission's OPS has not questioned the quality of IP's corrective actions for the December 2000 incident. (IP Ex. 14.3, pp. 15-16) IP stated that conducting a root cause analysis is not an end in itself but rather is a means to determine what to do to prevent the problem or incident from occurring again. IP concluded that since Mr. Lounsberry has not suggested any deficiencies in the corrective actions that IP implemented, there is no point to his continuing assertions that IP failed to conduct an adequate root cause analysis. (IP Ex. 14.3, p. 15)

IP further argued that there is no connection between the December 2000 incident or its causes and the turbine injection metering measurement error that was the cause of the decline in the performance of the Hillsboro Field, and that Mr. Lounsberry

did not show any connection. Further, even if the Commission were to conclude that IP's investigation of the root cause of the December 2000 incident was insufficient or not aggressive enough, this would provide no basis to cast doubt on the sufficiency and diligence of IP's investigation into the causes of the Hillsboro Field deliverability decline, or to question the sufficiency of the resources and attention that Illinois Power devoted to that problem. (IP Ex. 14.3, p. 16)

v. Hillsboro Storage Field Metering

IP responded to Mr. Lounsberry's "overall storage concern" that IP did not pull the orifice plates on the Hillsboro well withdrawal meters from their installation in 1993 to the time of the Peterson metering review in 1999, and that IP should have inspected the orifice plates annually as specified in 83 Illinois Administrative Code Part 500, even though he acknowledged that Code Part 500 applies only to utility meters used to measure customer loads and therefore is inapplicable to the metering at the Hillsboro Field. (Staff Ex. 7.0, pp. 46-50) IP stated that although the orifice plates were not pulled for inspection from 1993 to 1999, when they were pulled they were found not to have degraded after six years of service and to still be service worthy. (Rev. IP Ex. 14.1, p. 35) Further, IP did have an inspection procedure for these meters, consisting of calibrating the differential transmitters of each orifice meter fitting, calibrating the pressure transmitters for each pipeline, and checking the calibration of the resistant temperature detectors for proper temperature input, as well as checking the signal tubing between the orifice fitting and the differential transmitter on each meter for fluids. (*Id.*) With respect to Mr. Lounsberry's citation of Code Part 500 as a basis for this concern, IP pointed out that he admitted that Part 500 is not applicable to the Hillsboro orifice meters. Therefore, IP stated, there is no point to his effort to evaluate IP's metering practices at Hillsboro against a standard that does not apply to those meters. (*Id.*, p. 33)

IP responded to Mr. Lounsberry's citation of the "AGA Gas Measurement Manual, Orifice Meters, Part No. 3" and his assertion that IP failed to follow minimum requirements from the AGA guidelines with respect to the Hillsboro metering. (Staff Ex. 17.0R, pp. 45-47) IP stated that this document, like Part 500, is applicable to custody transfer meters, and thus is not applicable to the Hillsboro orifice withdrawal meters. IP stated that the fact that it does not inspect the orifice plates in the Hillsboro withdrawal meters at the frequencies specified in Code Part 500 and the referenced AGA Guide does not support Mr. Lounsberry's assertions that IP did not place a high priority on accurate measurements at the Field. (IP Ex. 14.3, p. 17) IP stated that Mr. Lounsberry provided no reason why IP should have applied regulations, standards and guidelines that are not applicable to the metering at the Field. (IP Ex. 14.3, p. 18) Further, IP noted that the Peterson Engineering report on the Hillsboro metering found with respect to the withdrawal metering installations that "In general, the metering layout is well designed and is in general conformance with AGA Report #3, Part 2". (Rev. IP Ex. 14.1, p. 36)

IP stated that in any event the problem with the orifice withdrawal meter at the Hillsboro Field was not caused by deterioration due to a lack of maintenance but rather was due to the fact that the label placed on the orifice plate by its manufacturer stated that the orifice opening was the size that Illinois Power had ordered, when in fact the orifice opening was somewhat smaller than the labeled (and ordered) size. (IP Ex. 14.3, p. 17) Further, neither the incorrect size of the orifice meter plate opening nor the level of maintenance on the orifice metering was the cause of the deliverability decline experienced at the Hillsboro Field. (*Id.*, p. 18)

Finally, IP responded to Staff's contentions that IP "initially made a significant error" when reviewing the Hillsboro injection metering error, in that IP initially assumed that the turbine injection metering error and the withdrawal measurement error due to the incorrectly labeled orifice plate opening on one of the four withdrawal meters were approximately offsetting, and that this was an instance of IP "not fully investigating a problem at its storage facilities." (Staff Init. Br., pp. 48-49) IP stated that Staff's characterization of the facts is incomplete and misleading because it suggested that IP stopped investigating the cause of the Hillsboro deliverability decline, when the record showed exactly the opposite is true, as IP had shown at length. IP also emphasized that at the time to which Staff was referring, IP had discovered the turbine injection measurement error that was being caused by the operation of the Hillsboro compressors and had implemented corrective actions, as recommended by its outside engineering consultant, to eliminate it, so the actual cause of the Hillsboro deliverability decline had at that point been addressed.

vi. Gas Dispatch Tracking

IP responded to Mr. Lounsberry's final "overall storage concern" which was that IP's gas load forecasting and dispatch group failed to notice an extra bcf of gas entering its system each year and that this was an example of IP failing to adequately oversee its operations. IP pointed out that the 1 bcf of gas each year that Mr. Lounsberry referred to equates to about 4,000 mcf per day on average during the injection season. IP stated that, particularly during the months of April, May, October and November, when the purchased volume on any day is approximately 300,000-400,000 mcf, with approximately 120,000 mcf being injected into storage, 4,000 mcf would not stand out as a significant error. IP noted that volumes of customer-owned gas also enter the system and that on a real-time basis the dispatchers cannot distinguish between deliveries for transport customers and other deliveries into the system. On a July day the amount of gas entering IP's distribution system, including both IP purchases and the gas of transportation customers, could be 220,000 to 280,000 mcf; 4,000 mcf in a day would not be noticeable in the context of these daily incoming volumes. (Rev. IP Ex. 13.9, pp. 18-19) Further, IP's retail transportation tariff, Service Classification 76, allows transportation customers a daily variance of 50% between nominations and deliveries, which equates to a potential difference between the aggregate nominations and aggregate deliveries of transportation customers in the IP system of 30,000 to 35,000 mcf in a day, which is far in excess of the 4,000 mcf average daily measurement error that occurred. (Rev. IP Ex. 13.1, pp. 24-25; Rev. IP Ex. 13.9, pp. 18-19)

IP also pointed out that on any given day the line pack in IP's system could range from zero to 10,000 mcf. The additional amounts of gas that were entering the distribution system on a daily basis due to the Hillsboro injection metering error were less than the amount of gas IP typically has in its system as line pack (Rev. IP Ex. 13.1, pp. 24-25). Finally, IP stated that although its gas dispatchers know what actual pipeline deliveries are on any day, the dispatchers do not know the actual customer consumption on any given day to enable them to compare the two values to determine if the load is equal to deliveries. This is because the vast majority of IP's end use customers are not metered on a daily basis, but on a non-calendar monthly billing cycle basis. (Rev. IP Ex. 13.9, pp. 19) IP concluded that Mr. Lounsberry's assertion that IP's gas dispatchers should have noticed 1 bcf of additional gas each year entering IP's system is unsupportable when analyzed in the light of operational realities and the daily volumes on the gas system.

vii. Efficiency of Storage Field Operations

Illinois Power presented several analyses depicting the overall efficiency of its operation of the Hillsboro Storage Field relative to other storage fields, in response to generalized assertions by Mr. Lounsberry that IP was not fulfilling its obligation to provide "adequate, efficient, reliable, environmentally safe and least-cost public utility services". IP stated that these analyses show that Hillsboro has been operated efficiently relative to other storage fields, Staff's criticisms notwithstanding. (IP Rep./Br., p. 64)

IP Exhibits 17.2 and 17.3 ranked 41 U.S. gas aquifer storage reservoirs in terms of the ratio of working gas to total gas in storage. The list of reservoirs and the operating data was taken from a database compiled by the International Gas Union and presented at a 2003 conference; the data was not selected by Illinois Power. (See IP Ex. 17.1, p. 19) IP stated that a higher ratio of working gas to total gas indicates greater efficiency, since a larger portion of the total gas inventory is available to cycle (i.e., to withdraw for delivery to customers). (IP Ex. 17.1, p. 19) IP Exhibit 17.2 ranked Hillsboro using its full design working gas inventory of 7.6 bcf and showed that Hillsboro ranked in the top third of the U.S. aquifer storage reservoirs listed. IP's Shanghai Storage Field ranked just slightly below Hillsboro in this comparison. IP Exhibit 17.3 ranked Hillsboro using the working gas volume of 2.6 bcf that was cycled in 2003-2003. Although this exhibit showed, of course, that Hillsboro fell in the rankings, Hillsboro still ranked above nine other aquifer gas storage fields in Illinois and Indiana based on this measure of efficiency. (*Id.*, pp. 19-20)

IP responded to Staff's criticism of this analysis, which was that the ratio of working gas to base gas is largely dependent on the geology and physical characteristics of the reservoir itself, and not on the utility's actions. IP explained that IP Exhibits 17.2 and 17.3 took geography and physical characteristics into account. Specifically (i) only aquifer storage reservoirs (of which Hillsboro is one) were listed on these exhibits, and (ii) 63% (25 of 41) of the reservoirs listed are located in Illinois and

Indiana and eight others are located in Iowa. Only eight of the 41 aquifer gas storage reservoirs listed are located outside this three-state area centered on Illinois. (IP Ex. 17.6, p. 8) Thus, any differences in the geology and physical characteristics of the 41 storage reservoirs listed on the exhibits have only a minor impact on the performance comparison shown by the exhibits, given the geographic proximity of the listed reservoirs. (*Id.*) IP concluded that the fact that IP's aquifer storage fields place as high as they do on this comparison is indeed indicative of IP operating its fields in an efficient and effective manner. (*Id.*) (IP Rep. Br., p. 65)

IP also responded to Mr. Lounsberry's other criticism of these exhibits, which was that Nicor, which operates the top-rated storage field in Illinois per IP Exhibit 17.2, also operates a number of fields ranked near the bottom of the list, yet this utility's overall storage management should not vary significantly from field to field. (Staff Init. Br., p. 53) IP stated that Mr. Lounsberry's assertion is not a necessary inference. IP witness Hower pointed out that with its large number of gas storage reservoirs, Nicor has the ability to employ variations in its overall storage operation strategy from field to field. He also noted that, perhaps more significantly, the top-rated Nicor storage field (Troy Grove) has the highest withdrawal capacity of any of Nicor's storage fields; therefore it is logical to assume that this field gets the greatest amount of management attention among the storage fields in Nicor's portfolio. He concluded that the Nicor data reinforces the fact that the rankings on IP Exhibits 17.2 and 17.3 depict a measure of efficiency and are not driven by geology or physical characteristics of the listed reservoirs. (IP Ex. 17.6, p. 9; IP Rep. Br., pp. 65-66)

IP noted that its response to Mr. Lounsberry's generalized assertion that IP was not providing "adequate, efficient, reliable, environmentally-safe and least cost public utility services" with respect to its storage field operations was not limited to IP Exhibits 17.2 and 17.3. IP stated that it has increased efficiencies at its storage facilities by implementing advanced technologies as they have become available. For example, IP has improved the automation and remote control features of the control systems at the storage fields. IP witness Shipp testified that all of the fields have updated control systems that have been installed over the last eleven years. He explained that these upgraded control systems make the storage facilities more efficient operationally and improve IP's ability to monitor them, both on-site and from the Decatur dispatch center. Further, gas dispatchers in Decatur are now able to monitor the status and operations of the storage facilities. Mr. Shipp testified that IP has also adopted a standardized set of operations software at the operator interfaces so that, if necessary, operators from one field can go to any other field and control it. (Rev. IP Ex. 13.1, pp. 22-23)

Additionally, Mr. Shipp testified that IP's storage fields have an excellent safety record, with only three lost-time accidents at the fields in the last ten years and no lost-time accidents in the last six years. He stated that IP's storage field operators receive extensive training on numerous safety-related topics including fire safety training, and that IP has never had an incident that endangered public safety at any of its gas storage facilities. (Rev. IP Ex. 13.1, p. 20) IP also pointed out that the Commission's OPS audits each of IP's seven storage fields annually; these audits include all the records at

each field and verification that leakage surveys and pipeline patrols have been performed. The OPS has issued only one “Non-Compliance” and two “Observations” to IP in total for all seven of IP’s fields in the last five years; the issues associated with these findings were minor and were addressed immediately by IP. (*Id.*, p. 18) (IP Rep. Br., pp. 66-67)

Finally, on IP Exhibit 17.4, IP presented a ranking of the 41 aquifer storage reservoirs in terms of the ratio of the maximum operating pressure to the original reservoir pressure. Hillsboro has the lowest ratio on this list and Shanghai the fourth lowest. IP witness Hower testified that the easiest way for an operator to increase inventory and deliverability is to operate a reservoir at a high pressure relative to the original reservoir pressure. He noted, however, that this practice can be unsafe and unwise, because it increases the possibility of gas leaks or migration outside the reservoir as well as structural damage or compromise to the integrity of the reservoir. Mr. Hower explained that the rankings of Hillsboro and Shanghai IP Exhibit 17.4 show that IP has not resorted to this practice but rather has operated its aquifer storage fields in a safe and conservative manner. (IP Ex. 17.1, pp. 21-22)

3. Commission Conclusion

Based on its review of the record and of the arguments of Illinois Power and Staff, the Commission concludes that the Hillsboro Storage Field should be found to be fully used and useful for purposes of this case, and that Staff’s proposed used and useful adjustment should not be adopted. In terms of a framework for this determination, the Commission notes that under Sections 9-211 and 9-212 of Act, the Hillsboro Storage Field is used and useful if it is “necessary” to meet customer demand or “economically beneficial” in meeting customer demand. The Commission has discretion in making a used and useful determination, but as in all areas of our decision making we may not depart arbitrarily from our previously-applied standards and approaches. The Commission also notes that the purpose of this proceeding is to establish base gas rates that will go into effect on or about May 20, 2005, and be in effect thereafter, until at least January 1, 2007. Therefore the focus of our used and useful analysis should be on the current operating status of Hillsboro and its foreseeable operating status, as established in the record, during the period in which the new rates to be established in this proceeding are in effect.

With this in mind, we find that the record establishes without contradiction that Hillsboro was restored to its original design peak day deliverability value of 125,000 mcf/day prior to the 2003-2004 winter season, has continued to operate at that rating for the 2003-2004 and 2004-2005 winter seasons, and is expected to continue to operate at that level into the future. This has not been disputed by Staff. Therefore, any used and useful analysis conducted or relied on by the Commission in this case must take into account that Hillsboro is operating at its full design peak day deliverability of 125,000 mcf/day. Stated differently, no used and useful adjustment can be premised, in whole or in part, on an assumption that Hillsboro is not operating at a peak deliverability of 125,000 mcf/day. To the extent that a three-year analysis is appropriate for purposes

of this case, our most recent and most definitive decision on the applicable three-year period, *Commonwealth Edison Company*, Docket 94-0065 (Jan. 9, 1995), identified earlier in this Order, establishes that the three-year period should center on the year that the new rates established in the rate order go into effect. For purposes of this case, such three-year period is the period 2003-2004, 2004-2005 and 2004-2006. The record shows that during each of these three winter seasons, Hillsboro operated at or is projected to operate at its full peak day deliverability rating of 125,000 mcf/day. Therefore, use of the three-year period 2003-2004, 2004-2005 and 2004-2006 is consistent with our determination that the used and useful analysis must reflect that Hillsboro is operating at a peak rating of 125,000 mcf/day.

The Commission finds that the record establishes that in its current operating condition, the Hillsboro Storage Field is used and useful because it is necessary to meet customer demand. The record indicates that in providing 125,000 mcf/day of peak deliverability, the Hillsboro Field provides a supply resource and reliability benefit that likely could not be replaced by purchases of incremental pipeline FT capacity given the constrained pipeline market conditions into Illinois established by the record. Additionally, Hillsboro is an integral part of IP's gas resource portfolio particularly given that it is a supply resource serving both the Metro East portion of IP's gas service area and the Decatur portion of IP's service area.

The Commission also finds that the record establishes that the Hillsboro Storage Field is used and useful because it is economically beneficial in meeting customer demand. The record establishes that at its peak deliverability rating of 125,000 mcf/day and based on the working gas volume it was projected to cycle for 2004-2005, 4.1 bcf, the pipeline FT and seasonal gas cost savings that Hillsboro provides (which would otherwise translate to higher gas costs through the PGA), exceed the annual revenue requirement to include Hillsboro in rate base as 100% used and useful. The record shows that the seasonal gas cost savings provided by Hillsboro exceed its annual revenue requirement whether the various pricing and other assumptions used by IP or the pricing and other assumptions used by Staff witness Lounsberry are employed. Staff's evidence did not contradict this. Our recent decision in the AmerenUE and AmerenCIPS gas rate cases, Dockets 02-0798, 03-0008 & 03-0009 (Cons.) (Oct. 22, 2003), establishes that such a showing provides an appropriate basis for concluding that an existing storage field asset is fully used and useful.

The Commission also finds that there are sufficient flaws in the used and useful analysis presented by Staff to render it not useful for purposes of making the used and useful determination in this proceeding. As pointed out by IP, the single pipeline contract used by Staff to establish the value of peak capacity in its analysis is only an intrastate contract and does not include the pipeline transportation costs to move gas from the gas producing regions to IP's service area. Therefore, it is not reflective of the full value of peak day deliverability provided by Hillsboro. Staff did not contradict this fact. Additionally, Staff's use of this single contract does not take into account that Hillsboro provides peak day resources to two distinct regions of IP's service area. The Commission also has concerns about Staff's use of five years of historic gas price

information to calculate seasonal gas cost savings in its analysis, rather than more current information. The record establishes that gas commodity market conditions are materially different from what they were several years ago, and these differences impact pricing. Staff's gas price data set is also inconsistent with our determination that the used and useful determination must incorporate current and reasonably foreseeable information concerning Hillsboro's operations. Additionally, as pointed out by Illinois Power, under Staff's test it would be necessary for Hillsboro to operate at its 125,000 mcf/day peak deliverability rating and cycle its full design working gas volume, 7.6 bcf, for three consecutive winters in order to be found 100% used and useful. The record shows that this test is inconsistent with operating realities and is unduly stringent. The Commission notes that in various recalculations of Staff's analysis, IP showed the Hillsboro Storage Field to be between 84% and 97% used and useful. Given the highly stringent nature of Staff's test, the Commission concludes that these percentages are sufficiently high to support a conclusion that Hillsboro is fully used and useful for purposes of this case.

Finally, the Commission has considered the items identified by Staff as "overall storage concerns" and Illinois Power's responses to these concerns. The Commission does not find these overall storage concerns, either individually or collectively, to warrant a used and useful adjustment in this case.

D. Overall Conclusion on Rate Base

Based on the gas utility rate base as originally proposed by IP, the uncontested adjustments to rate base as summarized in Section III.A above, and the Commission's conclusions with respect to the Hillsboro Storage Field base gas inventory and the Hillsboro Storage Field used and useful status in Sections III.B and III.C, above, the gas utility rate base for AmerenIP approved for purposes of this proceeding is \$497,883,000. The rate base may be summarized as follows:

Component	Amount (000)
Gross Utility Plant in Service	\$864,193
Less Accum. Dep. and Amort.	(421,787)
Net Plant in Service	442,406
Additions to Rate Base	
Cash Working Capital	(1,073)
Gas Stored Underground-Noncurrent	27,135
Depr. Res. – Contrib. Elec. Distrib.	1,164
Materials & Supplies and Working Gas Inventory	41,430
Deductions From Rate Base	
Customer Advances for Construction	(6,703)
Customer Deposits	(6,476)
Rate Base	\$497,883

The development of the overall gas utility rate base adopted for purposes of this proceeding is shown in the Appendix to this Order.

IV. GAS DEPRECIATION RATES

As part of its filing in this case, Illinois Power requested approval of revised depreciation rates for its gas utility. IP last performed a gas depreciation study in 1992; the results of that study were approved by the Commission in Docket 92-0465 and were incorporated into the setting of IP's gas rates in its last gas rate proceeding, Docket 93-0183. (IP Ex. 2.1, pp. 27-28)

IP's proposed revised depreciation rates are based on a study prepared for IP by Foster Associates, Inc. (IP Ex. 11.3) Dr. Ronald E. White, Executive Vice President and Senior Associate of Foster Associates, sponsored the depreciation study and submitted prepared testimony describing it. (IP Ex. 11.1) He testified that Foster Associates is recommending a separation of the accrual rate for net salvage from the accrual rate for the investment portion of a plant account. Under this approach, depreciation charges for the investment portion of a plant account will be accumulated in primary account investment reserves, while net salvage accruals will be accumulated in function net salvage reserves. He stated that the benefits derived from a separate accrual rate for net salvage include reduced field reporting, simplified accounting and improved monitoring and control of reserve imbalances. However, Foster Associates is not recommending separation of the accrual rates for net salvage and the investment portion of the plant accounts for general plant accounts, because gross salvage and cost of removal for plant items classified as general plant are generally easier to identify than net salvage associated with transmission and distribution accounts. (IP Ex. 11.1, pp. 12-13)

Dr. White also testified that an analysis comparing the computed and recorded depreciation reserves for IP at December 31, 2003, showed a difference of \$(27,192,728) between the recorded depreciation reserve and the computed reserve. He testified that a proportionate amount of this measured reserve imbalance would be amortized over the composite weighted-average remaining life of each depreciation rate category. (IP Ex. 11.1, p. 13)

Finally, Dr. White testified that Foster Associates is recommending a rebalancing of depreciation reserves for IP. This will entail (i) maintaining recorded reserves by primary account, which IP has not done in the past, and (ii) separating the recorded reserve into an investment portion and a net salvage portion, such that net salvage can be recorded at the function level and depreciation expense exclusive of net salvage can be accrued by primary account. He explained that a redistribution of the recorded reserve is therefore necessary to develop an initial investment reserve balance for each primary account and a net salvage reserve balance for each function consistent with the estimates of retirement dispersion and net salvage rates developed in Foster

Associates' study. Dr. White explained how the redistribution of the recorded reserve was calculated. (IP Ex. 11.1, p. 14)

IP's current Commission-approved depreciation rates were established at the function level (with the exception of general plant) and are as follows (IP Ex. 11.3, p. 16):

Underground Storage	1.76%
Transmission	2.29%
Distribution	3.60%
General Plant	
Structures and Improvements	2.04%
Transportation Equipment	4.81%
Tools, Shops and Garage Equipment	4.20%
Laboratory Equipment	4.20%
Power Operated Equipment	3.89%
Miscellaneous Equipment	<u>4.20%</u>
Total General Plant	<u>4.41%</u>
Total Gas Utility	<u>3.25%</u>

The following table shows the proposed depreciation rates, by account (IP Ex. 11.3, p. 16):

Account Description	Proposed Rate
Underground Storage	
351.20 Compressor Station Structures	1.64%
351.30 Meas. and Reg. Stations	1.72%
351.40 Other Structures	1.76%
352.00 Wells	1.71%
352.20 Reservoirs	1.59%
352.30 Nonrecoverable Natural Gas	1.26%
353.00 Lines	1.96%
354.00 Compressor Station Equipment	2.09%
355.00 Meas. and Reg. Equipment	2.41%
356.00 Purification Equipment	1.74%
357.00 Other Equipment	2.42%
Total Underground Storage	1.81%
Transmission	
366.00 Structures and Improvements	1.32%
366.10 Compressor Station Structures	2.04%
366.20 Meas. and Reg. Station Structures	2.23%
366.30 Other Structures	2.40%
367.00 Mains	1.22%
368.00 Compressor Station Equipment	1.96%

369.00 Meas. and Reg. Station Equipment	2.12%
Total Transmission Plant	1.39%
Distribution	
375.00 Structures and Improvements	1.51%
376.00 Mains	1.97%
378.00 Meas. and Reg. Equipment – General	1.99%
379.00 Meas. and Reg. Equipment – City Gate	2.96%
380.00 Services	2.17%
381.00 Meters	2.18%
382.00 Meter Installations	2.82%
383.00 House Regulators	2.82%
385.00 Industrial Meas. and Reg. Station Equip.	2.80%
Total Distribution Plant	2.17%
General	
390.00 Structures and Improvements	2.32%
392.00 Transportation Equipment	0.97%
394.00 Tools, Shop and Garage Equipment	2.12%
395.00 Laboratory Equipment	0.91%
396.00 Power Operated Equipment	2.53%
398.00 Miscellaneous Equipment	3.05%
Total General Plant	1.66%
TOTAL INVESTMENT	2.00%
Net Salvage	
108.42 Underground Storage	0.19%
108.43 Transmission	0.26%
108.44 Distribution	1.04%
TOTAL NET SALVAGE	0.83%
TOTAL UTILITY	2.81%

A comparison of the current depreciation rates to the proposed depreciation rates shows that the proposed accrual rates are lower than the present rates in 27 of the 36 primary accounts included in the Foster Associates study. Dr. White calculated that based on December 31, 2003 plant balances, adoption of the proposed depreciation rates would reduce annualized depreciation expense by \$3,200,674. (IP Ex. 11.1, p. 16)

Staff witness Burma Jones reviewed IP's depreciation study. She testified that the current case is the proper venue for IP to propose a change to its depreciation rates given that it has been approximately eleven years since the last change in IP's depreciation rates. She stated that the current depreciation study was warranted and that the results appear reasonable; therefore, she stated that she had no objection to

the proposed depreciation rates. (Staff Ex. 2.0, pp. 15-16) No other party raised any issues concerning, or stated any objection to, the proposed depreciation rates.

Based on its review of the record, including the depreciation study submitted by IP, the Commission concludes that IP's proposed depreciation rates are reasonable and should be approved. The Commission concurs with Staff as well as IP that a review and revision to IP's depreciation rates is timely in connection with this proceeding. The Commission concludes that the separation of the accrual rates into an investment portion and a net salvage portion, the redistribution of the recorded reserve and the amortization of the reserve imbalance as estimated in the Foster Associates study, and the incorporation of these steps into the development of the proposed depreciation rates, as described in IP Exhibit 11.3, are reasonable and should be approved, pursuant to Section 5-104(a) of the Act (220 ILCS 5/5-104(a)).

V. OPERATING REVENUES AND EXPENSES

Illinois Power's proposed operating income statement, as presented in its direct case filing, was based on test year 2003 actual expenses as adjusted by a number of proposed pro forma adjustments. Some of these adjustments were objected to by other parties while others of these adjustments were not objected to by other parties. Additional adjustments to operating revenues and expenses were proposed by Staff and/or AG/CUB and were accepted by IP. Finally, as discussed in Section I of this Order, above, IP and Staff stipulated to the resolution of certain proposed adjustments to operating expenses as set forth in the Stipulation, and no other party objected to these Stipulated Resolutions. As a result, as of the close of the record, there were no remaining contested adjustments to operating revenues and expenses. The uncontested or agreed adjustments to operating revenues and expenses that are being adopted for purposes of this Order are discussed in Section V.A below.

A. Uncontested Adjustments to Operating Revenues and Expenses

1. Rate Case Expenses

IP proposed an adjustment to amortize its incremental expenses for outside services associated with this rate case over a three-year period. In the Stipulation, Staff and IP stipulated that a three-year period should be used for amortization of the rate case expenses. In addition, Staff witness Michael McNally proposed that a portion of the fees paid by IP to its cost of common equity witness, Ms. McShane, should be disallowed. In the Stipulation, IP stipulated with Staff to this adjustment.

2. Pension Expense

IP's estimated pension expense as calculated by its actuary constitutes a significant increase over its actual 2003 pension expense. IP proposed an adjustment to increase operating expenses by the portion of the pension expense increase allocated to the gas utility. (IP Ex. 2.1, p. 22) While no party objected in principle to this

adjustment, AG/CUB witness Effron and Staff witness Pearce noted that a portion of the adjustment should be capitalized reflecting that a portion of annual pension expense is charged to construction. IP agreed that a portion of the pension expense adjustment should be capitalized. In the Stipulation, IP and Staff stipulated to use of a 30% capitalization factor, as proposed by Mr. Effron and Ms. Pearce, for this purpose.

3. Company Use of Gas

IP proposed an adjustment to operating expenses to reflect the cost incurred to purchase gas for use at IP facilities, which is a cost not recoverable through the Purchased Gas Adjustment (“PGA”) charge. No party objected to this adjustment. (IP Ex. 2.15 and IP Ex. 2.36, p. 5, col. (AL))

4. Pass-Through Taxes and Related Accounting Fee

IP reduced operating expenses by the amount of certain pass-through taxes and charges it collects for governmental bodies, including municipal utility taxes, State public utility taxes, the Public Utility Fund assessment, and the energy assistance and renewable energy fund charges. (IP Ex. 2.16 and IP Ex. 2.36, p. 6, col. (AM)). In addition, IP accepted AG/CUB witness Effron’s position that in calculating the net revenue requirement on which the required revenue increase from base rates is based, the administrative fee that IP is allowed by statute to add to customer bills and to retain as a fee for billing, collecting and remitting municipal utility taxes should be included in miscellaneous revenues. (IP Ex. 2.35, p. 26)

5. 2004 Wage Increase Adjustment

IP adjusted operating expenses to reflect the known increases in gross payroll attributable to increases in employee salary levels and other salary adjustments scheduled to occur in 2004 for both union and non-union personnel. In calculating this adjustment, IP removed from the base 2003 payroll costs (i) payroll costs for employees whose positions have been eliminated and (ii) the portion of employee compensation applicable to incentive compensation payments, before applying the 2004 percentage increases. (IP Ex. 2.44 and IP Ex. 2.36, p. 3, col. (W))

6. Corporate Franchise Taxes

Operating expenses were adjusted for the portion allocated to the gas utility of an increase in IP’s corporate franchise taxes in 2004 over 2003 resulting from a change in law. (IP Ex. 2.18 and IP Ex. 2.36, p. 6, col. (AN))

7. Retirement of River Bend Facility

As discussed in the Rate Base section of this Order, in 2004 IP retired its River Bend facility. Accordingly, operating expenses were adjusted to remove the portion of

maintenance expenses and real estate taxes associated with this facility allocated to the gas utility. (IP Ex. 2.19 and IP Ex. 2.36, p. 6, col. (AO))

8. Charitable Contributions

Operating expenses were adjusted to incorporate IP's 2003 charitable contributions, which were previously recorded above the line in Account 930.2 but are now recorded below the line in Account 426.1 as the result of a 2003 revision to the USOA. This accounting change was not intended to impact the recoverability of expenses for donations for charitable, social and community welfare purposes in future rate proceedings. (IP Ex. 2.1, pp. 24-25, IP Ex. 2.20 and IP Ex. 2.36, p. 6, col. (AP))

9. Uncollectible Expenses

Test year uncollectible expenses were adjusted to reflect the average of IP's uncollectible expenses for the five-year period 1999-2003. (IP Ex. 2.21 and IP Ex. 2.36, p. 6, col. (AQ))

10. FICA Tax Increase

Operating expenses were increased to reflect higher FICA tax contributions in 2004 over 2003 due to a change in law that increased the amount of employee earnings on which employers are required to make FICA contributions. (IP Ex. 2.1, p. 26, IP Ex. 2.45 and IP Ex. 2.36, p. 4, col. (AE))

11. Donated Services

Operating expenses were increased to reflect the cost of gas and gas distribution services that IP provides to various municipalities at no charge or at discounted prices as franchise consideration under the terms of its franchise agreements. The cost of this free or discounted service is not recovered through the PGA charge. (IP Ex. 2.1, pp. 26-27, IP Ex. 2.23 and IP Ex. 2.36, p. 6, col. (AR))

12. Payments to Severed Employees

Operating expenses were reduced to remove (i) the gas utility-allocated portion of wages paid to employees in 2003 whose positions have been eliminated and (ii) severance payments made to these employees. (IP Ex. 2.24 and IP Ex. 2.36, p. 6, col. (AS))

13. Revised Gas Depreciation Rates

As described in Section IV of this Order, in this case IP is proposing new gas utility depreciation rates based on a recently completed depreciation study. The overall impact of the new depreciation rates is to lower the annual depreciation expense. IP

calculated test year depreciation expense by applying the new depreciation rates to the December 31, 2003 plant balances. (IP Ex. 2.25 and IP Ex. 2.36, p. 7, col. (AU))

14. Depreciation Expense Related to Plant in Service Adjustments including Retirements

IP increased or decreased test year depreciation expense, as applicable, to reflect the impacts on depreciation expense of the various plant in service adjustments to rate base, including the 2004 capital additions, completed CWIP not classified as plant in service at December 31, 2003, small CWIP projects, advanced metering equipment, plant retirements, the adjustment to the capital cost of the Hillsboro well and other plant-related adjustments described in the Rate Base section of this Order. The depreciation expense adjustments relating to gas plant additions that would be included in rate base prospectively utilized IP's new gas depreciation rates. (IP Ex. 2.50, IP Ex. 2.31, IP Ex. 2.42, IP Ex. 2.43 and IP Ex. 2.36, p. 7, col. (AT) and (AZ) and p. 5, col. (AF) and (AG))

15. Company Use of Electricity

Operating expenses were increased to reflect the gas utility-allocated portion of the cost of electricity purchased by IP for use in company facilities. This cost is charged to Account 555, Purchased power. (IP Ex. 2.1, pp. 29-30, IP Ex. 2.27 and IP Ex. 2.36, p. 7, col. (AV))

16. Retirement of East St. Louis Facility

During the course of 2003, IP retired a facility in East St. Louis. Operating expenses were adjusted to remove maintenance expenses and real estate taxes incurred for this facility during 2003 prior to its retirement. (IP Ex. 2.1, p. 30, IP Ex. 2.28 and IP Ex. 2.36, p. 7, col. (AW))

17. Removal of Purchased Gas Costs

The expense for gas purchased to supply customers, which is included in IP's overall test year operating expenses but which is recovered through the PGA charge, was removed from operating expenses, since these purchased gas costs will not be taken into account in determining the revenue requirement to be recovered through base rates. (IP Ex. 2.29 and IP Ex. 2.36, p. 7, col. (AX))

18. Sales Expense

IP reduced operating expenses by removing demonstration and selling expenses, certain advertising expenses, revenues and expenses from merchandising, jobbing and contract work, and other sales expense recorded in Accounts 911 through 916. (IP Ex. 2.1, pp. 30-31, IP Ex. 2.30 and IP Ex. 2.36, p. 7, col. (AY))

19. Advertising Expense

In rebuttal testimony, IP agreed to accept a portion, but not all, of the adjustments proposed by Staff witness Pearce to remove certain advertising expenses from operating expenses. (IP Ex. 2.36, p. 4, col. (X) and (Y)) Ms. Pearce subsequently withdrew a portion of her remaining adjustment. (Staff Ex. 12.0, pp. 12-13)) In the Stipulation, IP and Staff stipulated that the balance of Ms. Pearce's proposed adjustment, as shown on Staff Schedule 12.05, should be accepted.

20. Industry Association Dues

In rebuttal testimony, IP agreed to accept a portion, but not all, of the adjustments proposed by Staff witness Pearce to remove certain industry association dues payments from operating expenses. (IP Ex. 2.36, p. 4, col. (Z)) Subsequently, in the Stipulation, IP and Staff stipulated that the balance of Ms. Pearce's proposed adjustment, as shown on Staff Schedule 12.06, should be accepted.

21. Lobbying Expense

Staff witness Pearce and AG/CUB witness Effron proposed adjustments to remove certain "lobbying" expenses from operating expenses. In rebuttal testimony, IP agreed to accept a portion, but not all, of the adjustment proposed by Staff witness Pearce. (IP Ex. 2.36, p. 4, col. (AA)) Subsequently, in the Stipulation, IP and Staff stipulated that the balance of Ms. Pearce's and Mr. Effron's proposed adjustment, as shown on Staff Schedule 12.07, should be accepted.

22. Injuries and Damages

IP accepted the adjustment proposed by Staff witness Pearce and AG/CUB witness Effron to remove from operating expenses the portion of test year injuries and damages expense related to Incurred But Not Reported claims. (IP Ex. 2.36, p. 4, col. (AB))

23. General Research Expense – EPRI Payments

IP accepted the adjustment proposed by Staff witness Pearce to reduce gas operating expenses by removing from general research expense certain payments made to the Electric Power Research Institute. (IP Ex. 2.36, p. 4, col. (AC))

24. Correction of Depreciation and Amortization Expense on General and Intangible Electric Plant Allocated to the Gas Utility

In rebuttal testimony, IP indicated that the amount of depreciation and amortization expense on electric general and intangible plant allocated to the gas utility had been overstated. Accordingly, IP adjusted operating expenses to remove the

excess depreciation and amortization expense. (IP Ex. 2.35, p. 49 and IP Ex. 2.36, p. 5, col. (AH))

25. Interest on Customer Deposits

Staff witness Hathhorn proposed that interest on customer deposits held by IP should be included in operating expenses. (Staff Ex. 9.0 and Sched. 9.03) IP agreed with Ms. Hathhorn but disagreed with the amount of her proposed adjustment. (IP Ex. 2.35, pp. 27-28 and IP Ex. 2.36, p. 5, col. (AI)) In her rebuttal testimony, Ms. Hathhorn agreed with IP's calculation of this adjustment. (Staff Ex. 13.0, pp. 1-2)

26. Incentive Compensation and Stock Options Expense

In the Stipulation, IP and Staff stipulated that incentive compensation costs (including the related FICA taxes) and costs for employee stock options incurred during 2003 should be excluded from the computation of the revenue requirement, as proposed by Staff witness Pearce and AG/CUB witness Effron. As noted in the Rate Base section of this Order, a portion of these costs is expensed and a portion of these costs is charged to construction and capitalized. Therefore, the adjustments for incentive compensation and stock option costs entail both a reduction to operating expenses and a reduction to rate base, as reflected on ICC Staff Exhibit 12.0, Schedule 12.02 and on Settlement Schedule 3, respectively.

27. Acquisition-Related Operating Expense Savings

AmerenIP proposed to reduce test year 2003 operating expenses by the amount of the expense savings estimated to be achieved through a number of initiatives that are being implemented as a result of IP's acquisition by Ameren and its integration into the other Ameren companies. The amount of this reduction to operating expenses is \$8,544,000. AmerenIP witness Robert Porter presented information on the operating expense savings that Ameren expects will be realized for AmerenIP's gas utility operations due to synergies achieved from the integration of IP into the Ameren companies. (IP Exs. 19.1-19.2) The list of projects and cost savings on which this adjustment is based were originally identified on Attachment B to Applicants' Exhibit 47.0 in Docket 04-0294, the proceeding in which the Commission approved Ameren's acquisition of IP. The adjustment amount of \$8,544,000 was determined by identifying the projects that will have cost-reduction impacts for AmerenIP's gas utility operations, summing the savings expected from those projects, and applying the gas utility allocation factor used for allocating expense items in this case, 30.57%. The adjustment did not incorporate savings from projects that will produce savings solely for AmerenIP's electric operations.

Mr. Porter testified that the expense reduction of \$8,544,000 by which gas utility operating expenses are being adjusted in this case are part of the overall \$33 million of non-fuel operation and maintenance ("O&M") savings identified on Attachment B to Applicants' Exhibit 47.0 in Docket 04-0294. He pointed out that the Order in Docket 04-

0294, in particular Conditions to Approval 20 to 23 in Appendix A to the Order, imposes specific obligations and procedures on Ameren and AmerenIP with respect to demonstrating progress towards implementing the projects listed on Attachment B to Applicants' Exhibit 47.0 and, ultimately, reflecting the resulting \$33 million of O&M savings in AmerenIP's revenue requirement in future electric and gas rate cases. He noted that the Commission should recognize that AmerenIP is proposing to incorporate \$8,544,000 of these projected operating expense savings in the calculation of the gas utility revenue requirement in this rate case. (IP Ex. 19.1, pp. 4-5) In the Stipulation, Staff and AmerenIP stipulated to incorporate AmerenIP's proposed \$8,544,000 O&M expense reduction for acquisition-related savings in the revenue requirement in this case.

28. Relocation Reimbursements

As discussed in the Rate Base section of this Order at Section III.A.18, in the Stipulation IP and Staff stipulated to the use of the "compromise approach" to accounting for relocation reimbursements that was proposed by IP witness Carter and accepted by Staff witness Jones. Adoption of the "compromise approach," which effects a change in the method of accounting for relocation reimbursements, results in a reduction in test year depreciation expense.

B. Overall Conclusion on Operating Expense Statement

Based on the gas utility operating expense statement as originally proposed by IP and the uncontested adjustments to operating revenues and expenses as summarized in Section V.A above, the total gas utility operating expenses for AmerenIP approved for purposes of this proceeding are \$100,730,000. This amount includes (i) the additional federal and State income tax expense associated with the revenue increase authorized in this proceeding and (ii) the incremental adjustment to uncollectible accounts expense associated with the revenue increase authorized in this proceeding. The operating expense statement may be summarized as follows:

Component	Amount(000)
Operation & Maintenance	\$ 20,109
Customer Accounts	7,382
Customer Service and Information	934
Administrative & General	20,826
Depreciation & Amortization	23,743
Taxes Other Than Income Taxes	5,989
Uncollectibles Expense	3,983
Rounding	1
Total Operating Expenses Before Income Taxes	82,967
State Income Tax	3,264
Federal Income Tax	14,499

Total Operating Expenses	\$100,730

The development of the overall gas utility operating expenses adopted for purposes of this proceeding is shown in the Appendix to this Order.

VI. COST OF CAPITAL AND RATE OF RETURN

Evidence concerning the cost of capital and rate of return was submitted by three parties in this docket, namely, Illinois Power, Staff and CUB. In the Stipulation, IP and Staff stipulated to a cost of common equity of 10.00% and an overall rate of return on rate base of 8.18%. IP and Staff also stipulated to the balances and cost rates for long-term debt, transitional funding trust notes ("TFTN") and preferred stock and the balance of common equity, to be used in calculating the overall rate of return. The balances incorporated in the Stipulated Resolution are as of November 30, 2004, and reflect the reduction of IP's common equity balance resulting from elimination of an intercompany note in connection with the acquisition by Ameren, debt redemptions implemented subsequent to the acquisition through December 1, 2004, and equity infusions by Ameren following the acquisition. Also per the Stipulated Resolutions, the rate of return incorporates an adjustment to eliminate a portion of IP's unamortized loss on reacquired debt that had previously been written off in connection with the deregulation of electric generation, as proposed by Staff witness Ms. Freetly. The overall rate of return of 8.18% is calculated as follows as shown on Schedule 8 to both Appendix A and Appendix B to the Stipulation:

Class of Capital	Amount	Percent of Total Capital	Cost	Weighted Cost
Long-Term Debt	\$ 684,908,607	29.70%	6.27%	1.86%
TFTN	\$ 350,934,973	15.22%	5.95%	0.91%
Preferred Stock	\$ 45,786,945	1.99%	5.01%	0.10%
Common Equity	<u>\$1,224,252,958</u>	<u>53.09%</u>	10.00%	<u>5.31%</u>
Total Capital	\$2,305,883,483	100.00%		
Weighted Average Cost of Capital				8.18%

The Commission notes that the rate of return on common equity and the overall rate of return are both within the range of the recommendations presented by the cost of capital witnesses in this case. The Commission adopts the overall rate of return on rate base of 8.18%, including the capital structure components and cost rates shown above, as fair and reasonable for purposes of this proceeding.

VII. COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN

A. Cost of Service Study

1. Average and Excess versus Average and Peak Allocation Method

a. IP's Position

In its direct case, IP used the Average & Excess ("A & E") demand cost allocation method in its gas embedded cost of service study. (IP Ex. 5.1, pp. 3-9) Staff, in its direct case, advocated the use of the Average & Peak ("A & P") method. (Staff Ex. 6.0, pp. 5-10) Both AmerenIP witness Althoff and Staff witness Lazare explained the differences and/or similarities between the A & E and A & P methods. (IP Ex. 5.6, pp. 3-5; Staff Ex. 6.0, pp. 7-10) IP notes that in general, the "average" component of both methods is effectively determined in the same manner. However, with the A & E method, customer class non-coincident peak demand is utilized in the "excess" calculation, recognizing that not all customers peak at the time of the annual total delivery system peak, whereas in the A & P method, the class peak coincident with system peak is used in the "peak" portion of the allocation. (IP Ex. 5.6, p. 3) After due consideration, AmerenIP agreed for purposes of this case to employ the A & P method, with one modification in regard to the allocation of transmission and distribution plant ("T&D"), namely, to exclude the peak demands of grain drying and asphalt customers from the calculation. (IP Ex. 5.6, pp. 5-6) Because the Commission has in recent gas rate cases supported the A & P method as opposed to the A & E method and because the net results in employing the two different cost of service methods are reasonably close, AmerenIP agreed to use the A & P method. (*Id.*; IP Ex. 5.10, pp. 2-3) IP witness Althoff presented the following comparison of the results in terms of the allocation of T&D costs to the customer classes is as follows (IP Ex. 5.10, p. 3):

Service Classification	Transmission		Distribution	
	A&P	A&E	A&P	A&E
51	52.19%	54.04%	66.15%	67.32%
63	15.38	15.90	18.49	18.78
64	4.72	4.99	5.32	5.55
65	4.31	3.69	3.02	2.51
66	1.53	1.41	0.53	0.49
76	16.12	13.55	6.40	5.23
90	5.75	6.42	0.09	0.12
Total	100.00%	100.00%	100.00%	100/00%

IP noted that there is but a few percentage points difference between the two methods in terms of the percent of the T&D allocators by class. For example, customers in the SC 76 class see a 2.57 percentage point difference in the allocation of transmission costs and a 1.17 percentage point difference in the allocation of distribution costs between the two methods. AmerenIP stated that although it believes that on a theoretical basis the A&E allocation method is superior, it agrees to use a modified A&P approach in this case due to the recent trend in Commission decisions on this point in gas rate cases and, more significantly, the minimal difference in results produced in the context of this case.

- b. Staff's Position**
- c. IIEC's Position**
- d. Commission Conclusion**

Based on its review of the record, the Commission concludes that the A&P method, as modified by IP with respect to the seasonal gas customers, is reasonable and should be adopted for cost allocation purposes in this proceeding. Use of the A&P method was originally proposed by Staff, and Staff agreed with IP's modification to the A&P method for purposes of this proceeding. The Commission also notes that the record in this case shows there to be minimal differences between the percentages of total transmission plant and the percentages of total distribution plant allocated to the customer classes whether the A&E method or IP's modified A&P method is used in this case. The Commission emphasizes that its conclusion on this issue is not driven by precedent but by the record including in particular the minimal differences in results between the two methods. The Commission emphasizes that the choice of the appropriate cost allocation method should be based primarily on the facts and circumstances of, and the record developed in, each rate case.

2. Allocation of Cost of Mains

a. IP's Position

As noted earlier in this Order, AmerenIP agreed with Staff to employ the A & P cost of service method for this case to allocate T&D plant (including mains), but with the peak demands of grain drying and asphalt customers excluded from the calculation. (IP Ex. 5.6, pp. 5-6) IP noted that Staff witness Lazare agreed with AmerenIP's modified A&P approach for the allocation of mains, noting that "Any customer classes that fail to use gas during the peak day should not be factored into the peak demand component of the A&P allocator", and that he incorporated IP's revisions into his cost of service study. (Staff Ex. 16.0, p. 2; IP Init. Br., pp. 65-66)

IP responded to IIEC's disagreement with IP's allocation of mains. IP noted that IIEC witness Rosenberg looked at the 10 largest customers on the system and derived from his analysis a claim that they were being over-allocated costs associated with mains. His analysis was based on a calculation that relied on IP's response to IIEC data request 1.34. Relying on information contained in the data request, he derived a cost of \$9.45 for 12-inch steel pipe. IP pointed out, however, as the data request response plainly stated, the information therein is not complete. IP noted that it was careful to point out in the response that while the information provided in the response was responsive to the data request, the mains costs associated with yet to be categorized plant from completed projects, main-related costs not directly categorized by main material and size, and pro forma adjustments, were not included. (IP Cross Ex. 2; IP Ex. 8.6, p. 10) Therefore, IP noted, Dr. Rosenberg used an incomplete data set in his analysis. (IP Init. Br., p. 66) IP stated that, in addition, Dr. Rosenberg failed to

account for the fact that mains are installed to serve all customers. IP stated that it is inappropriate to select some portion of the mains and assume it is only serving these 10 large customers, because mains are common to all customers and are used to bring gas from the interstate pipeline into localized systems. IP stated that IIEC's analysis excluded completely the cost of these common mains and more importantly, did not allocate any of those costs to Dr. Rosenberg's select group of customers. (IP Ex. 5.6, p. 11) Finally, IP pointed out that Dr. Rosenberg did not actually identify the costs that have been invested to serve these ten large customers. He applied system average gross plant costs for the various types and sizes of high pressure pipes to the length of the type of pipe installed to each of these customers. He did not calculate the actual cost that IP has incurred to install the specific facilities that serve each of these customers. (Tr. 182-84) (IP Init. Br., p. 66)

IP also responded to BEAR's argument concerning the allocation of mains which was, in essence, that the "average" component for the cost of service method should be based on 365 days for all classes, meaning that in determining the proper allocation factor there should be recognition that grain drying and asphalt customers are consuming gas each day of the year, as is the case for IP's other customers. (BEAR Ex. 1, p. 4) IP witness Jones testified that IP allocated the average cost to SC 66 customers by taking their annual use divided by 61 days for grain dryers and 184 days for asphalt customers. These specific numbers of days were used for these customers because 90% of their usage for the year occurs during these time frames. IP noted that there are many days throughout the year when these customers consume no gas. Therefore, IP concluded, it was appropriate to recognize this cost causation factor in determining the correct allocator; to do otherwise would only serve to inappropriately place more costs on other customers. (IP Ex. 7.30, pp. 7-8; IP Init. Br., p. 67)

IP addressed the testimony of BEAR witness Smith that IP allocated a portion of peak costs to SC 66. IP witness Althoff testified in rebuttal that no excess or peak costs were allocated to SC 66. (IP Ex. 5.6, p. 5) IP also responded to BEAR witness Smith's testimony that distribution plant should reflect a measure of average and peak use, and that IP has built its system to serve its winter peak load. (BEAR Ex. 1, p. 5) IP stated that her premise was incorrect; IP plans and builds its T&D plant to meet customers' loads regardless of when or where they occur on the system. IP stated that for grain drying customers, groupings of pipes (or localized systems) are built to handle their loads during their peak drying season, which does not occur in the winter season. (IP Ex. 5.6, pp. 6-7) IP noted that the data show that grain drying customers' demands spike in the Fall. (IP Ex. 7.19, p. 20; IP Ex. 7.26) IP noted that in any event, no "peak" costs were allocated to SC 66. (IP Ex. 7.30, p. 10; IP Init. Br., pp. 67-68)

IP also pointed out that both the A&P and the A&E methods allocate only about 1.5% of the total transmission plant and only about 0.5% of the total distribution plant to SC 66; "capacity" related costs are a relatively minor part of the cost of service for this class. (IP Ex. 7.30, pp. 12-13; IP Init. Br., p. 68)

IP concluded that the allocation of mains it developed in this case, which was endorsed by Staff, is a broad based allocator that also distributes common mains to all customer groups. IP also stated that its allocator takes into account the usage periods of the customer classes. IP contended that IIEC's and BEAR's concerns did not provide a basis for not using IP's allocations. (IP Init. Br., p. 68)

- b. Staff's Position**
- c. IIEC's Position**
- d. BEAR's Position**
- e. Commission Conclusion**

Based on its review of the record, the Commission concludes that the allocation method for T&D plant as proposed IP and accepted by Staff is reasonable and should be adopted for purposes of this proceeding. The arguments presented by IIEC and by BEAR for adoption of a different allocation method or for modifications to the allocation method supported by Illinois Power and Staff do not demonstrate that any different or modified allocation methodology should be utilized in this case.

3. Allocation of Cost of Services

a. IP's Position

AmerenIP responded to the objections raised by Staff and BEAR to its cost of service allocator for services connecting customer premises to the gas system. Services are customer-related costs, which typically include capital investment associated with metering equipment and service connections as well as expenses for meter reading, billing, collecting and accounting. (IP Ex. 5.1, pp. 4-6) IP noted that Staff witness Lazare disagreed with IP's allocator because IP's allocation method, in his view, relied on questionable data concerning (i) the breakdown between steel service pipes and plastic pipes on the system and (ii) the relative costs of steel and plastic pipe; and that in support of his observation, he relied upon information provided by IP to the United States Department of Transportation ("USDOT"), which seemed to be inconsistent with data IP had used in performing its allocation. Additionally, Bear witness Smith also questioned the data set on which IP relied in developing the services allocator. She offered the view that cost differences between plastic and steel services varied with load, and that this factor should be taken into account in determining the allocation. (BEAR Ex. 1, pp. 8-9)

Based on the concerns expressed by Staff witness Lazare and BEAR witness Smith, AmerenIP witness Althoff performed an additional review of IP's services allocator. She observed that older services data tracked in IP's system did not record a diameter size when the corresponding services were installed; as a result, because the

size of the services were not tracked, these services were placed in the “zero” size category. She noted, however, more recently-installed services are now categorized by size. Accordingly, she relied on the more recently-installed services, which were categorized by size, to reallocate the older “zero” size services. IP stated that the reallocation of the “zero” size services took into consideration all services installed, both steel and plastic, which should resolve certain of the Staff and BEAR concerns. (IP Ex. 5.6, p. 14 and IP Ex. 5.10, p. 7; IP init. Br., p. 69) IP stated that the results based on its revised services allocator are fairly consistent with the information that IP provided to USDOT. Staff witness Lazare had testified that the USDOT report showed steel services at less than 40% of the total and plastic services at 60%; the revised services allocator indicates that 35% of the services are steel and 65% are plastic, which is consistent with both the information in the USDOT report and with AmerenIP’s records. IP pointed out that with this refinement, the Staff allocations and the revised IP allocations of total services costs to the customer classes track fairly closely, as summarized in a table presented in Ms. Althoff’s rebuttal (IP Ex. 5.6, pp. 16-17):

Service Classification	Staff Direct	Revised Company
SC 51	84.25%	80.23%
SC 63	14.59%	17.01%
SC 64	00.72%	01.70%
SC 65	00.11%	00.30%
SC 67	00.11%	00.28%
SC 68	0.01%	00.03%
SC 76	00.20%	00.46%
SC 90	00.00%	00.80%

AmerenIP stated that it provided a revised services allocator that is cost-justified; whereas Staff witness Lazare utilized a simple averaging based on an incomplete data set. IP noted that in Staff Schedule 6.04, page 3, Mr. Lazare relied on a unit cost for steel and plastic, added them together and divided by two. He then used the resulting average cost for service pipe sizes of 1-inch or less as the basis for developing size-cost weighting factors which are reflected in the fifth column of his Schedule 6.04. Mr. Lazare used the size cost weighting factors in the eventual development of the services allocation as reflected on Staff Schedule 6.04, page 4. IP noted that the only rationale given for averaging the unit cost of steel and the unit cost of plastic was that Staff found the original data set relied upon by IP to be unreliable. IP stated that this concern should no longer be a consideration since IP’s data set was improved and shown to be reliable in its rebuttal case. (IP Init. Br., pp. 70-71)

IP also noted that in developing his services allocator, Mr. Lazare relied in part on information provided by IP in response to IIEC data request 1.33. In particular (as reflected on Staff Schedule 6.03, which is the schedule that develops the unit cost), Mr. Lazare relied on the linear feet and gross plant balance information from the data request response. IP Pointed out, however, the data request response (IP Cross Exhibit 1) plainly stated that the information provided in the data request response did

not include all relevant costs. Specifically, the cost data provided in the response to IIEC data request 1.33 “do not reflect amounts associated with yet to be categorized main from completed projects, main related costs not directly categorized by main material and size (e.g. valves, fittings, filters, etc.) and proforma adjustments (e.g. CWIP to In-Service, etc.)” Therefore, IP concluded, the data request information could not provide the basis for depicting all the costs associated with service allocators. (IP Init. Br., p. 71)

IP further argued that a comparison of the relative cost differences between plastic and steel pipe showed Staff witness Lazare’s averaging method to be flawed. As shown in Ms. Althoff’s rebuttal testimony, depending on the size of the pipe, the variance in cost between plastic and steel can vary. For example, steel is 14 times more costly than plastic with regard to pipe that is 1 inch in diameter; however, steel is only 3 times more costly than plastic when considering 4 inch diameter pipe, and only 1.5 times greater for 6 inch diameter pipe. IP stated that as a result, Mr. Lazare’s simple averaging approach merely increased the cost assigned to the residential customer class. (IP Ex. 5.6, p. 16; IP Init. Br., p. 71)

IP contended that another flaw in Mr. Lazare’s approach was that it allocates no services cost to the SC 90 customer class. Mr. Lazare provided no evidence that there are no capital costs or expenses for services attributable to this customer. (IP Ex. 5.6, pp. 16-17; IP Init. Br., pp. 71-72)

IP also responded to BEAR witness Smith’s criticism of the original database that IP employed in determining the services allocator. IP explained that these issues were remedied in its rebuttal testimony. In response to Ms. Smith’s concerns about the relative costs of plastic and steel pipe and the sizes of the pipes in relationship to load, IP pointed out that she ignored the fact that pipe selection is based on the amount of gas delivered to the customer and the pressure at which customers are served, and that higher pressure customers require steel services, which are more costly than plastic pipe with respect to both material and labor (installation) costs. (IP Ex. 5.6, p. 18; IP init. Br., p. 72)

IP pointed out that in her rebuttal, BEAR witness Smith gave contradictory testimony, asserting at one point, “it is usually assumed that current costs can serve as a reasonable proxy for historic costs” but also stating that “using current costs as a basis for allocation would not be correct”. (BEAR Ex. 2, p. 7) (IP Init. Br., p. 72) AmerenIP witness Althoff testified that the use of current costs provides a better basis for allocating costs to customer classes as it eliminates the varying impacts of inflation on different plant items that is present when historic costs are used. In addition, IP’s books and records are maintained in accordance with the Federal Energy Regulatory Commission’s Uniform System of Accounts, which only requires the recording of plant and expenses by account without a customer class designation. Ms. Althoff also noted that the current cost approach is consistent with the Commission decisions in IP’s delivery service tariff cases (Dockets 99-0134 and 01-0432) where the Commission approved the use of current costs for electric service drops (as well as meters) to

allocate the embedded costs of those plant items. (IP Ex. 5.10, p. 11; see *Illinois Power Company*, Docket 01-0432, Order (Mar. 28, 2002), pp. 59-61)

In summary, IP concluded that its allocation of the costs of services to the customer classes, which was revised in IP witness Althoff's rebuttal testimony to address the concerns originally expressed by Staff witness Lazare, should be accepted for purposes of this case.

- b. Staff's Position**
- c. BEAR's Position**
- d. Commission Conclusion**

Based on the record, the Commission concludes that the revised services allocator presented by Illinois Power in its rebuttal testimony is reasonable and should be adopted for purposes of this proceeding. The Staff raised important questions about the services allocator originally presented by IP in its direct case and the quality of the data underlying that allocator, but IP satisfactorily addressed and resolved those issues through its revised data set and the resulting revised services allocator. The record is sufficient to support adoption of IP's revised services allocator. At the same time, the record reflects sufficient questions concerning the alternate allocator developed and presented by Staff, and its underlying methodology and supporting data set, to persuade the Commission that Staff's allocator is not preferable to IP's and should not be adopted in this proceeding. Finally, the issues raised by BEAR do not warrant adoption of a different services allocator than the revised allocator presented by IP, nor do they warrant any modifications to IP's services allocator. Among other things, the Commission notes that the approach used by IP of allocating the embedded costs of services and meters by using the current replacement costs of the meters that would be installed to serve the various customer classes, as employed by IP in this case, is a recognized and accepted cost of service technique that the Commission has accepted and approved in prior IP rate cases.

- 4. Use of AmerenIP Cost of Service Study versus Staff Cost of Service Study**
 - a. IP's Position**

AmerenIP strongly disagreed with Staff witness Lazare's position that Staff's cost of service model and study, rather than IP's cost of service study, should be used for purposes of this proceeding. (This issue is also discussed in Section VII.A.6 of this Order.) IP witness Althoff pointed to a number of flaws in the Staff model and study. In addition to concerns regarding terminology, the use of pasted values, and the lack of clarity with regard to certain of the formulas and other input data, she noted that Staff used data from IP's model to develop Staff's cost of service results. As she described it, Staff's model relied on a "hodge-podge of data." (IP Ex. 5.6, pp. 21-22) IP stated

that this is extremely problematic and is sure to lead to incomplete and confusing results. (P Init. Br., p. 73) Additionally, AmerenIP witness Jones testified that whereas IP's cost of service model is able to calculate the revenue requirement by function, the Staff model is deficient in this respect. (IP Ex. 7.19, p. 29) AmerenIP concluded that use of Staff's cost of service model cannot be the basis on which rates are set in this proceeding, as to do so would lead to unintended results. (IP Init. Br., p. 73)

IP urged that the final cost of service study used for revenue allocation and rate design purposes in this case should incorporate the Commission's determinations with respect to the remaining contested, substantive cost of service issues in this case. IP stated that the issues of what cost of service study to use and which cost of service model to use should be kept separate. IP stated that its cost of service model is fully capable of quickly and efficiently producing a final cost of service study, based on the final approved revenue requirement, that implements the Commission's decisions on the substantive cost of service issues. IP stated that Staff's model, in contrast, is not capable of producing cost information in sufficient detail to develop detailed pricing. Specifically, Staff's model is incapable of calculating the revenue requirement by function (i.e., storage, transmission, distribution, services, meters) and by rate class. IP stated that its cost of service model is capable of producing this level of detail which is used in the development of the specific proposed rates for each service classification. (IP Ex. 7.19, p. 29) Thus, IP concluded that its cost of service model should be used to produce the final cost of service study to be used in the final interclass revenue allocation and establishment of specific prices, based on the Commission's substantive determinations. (IP Rep. Br., p. 80)

b. Staff's Position

c. Commission Conclusion

Based on its review of the record and the arguments of the parties, the Commission concludes that Illinois Power's cost of service study should be adopted for revenue allocation and rate design purposes in this proceeding. Any determinations made by the Commission in this Order with respect to individual cost of service issues that are not already reflected in the cost of service study presented by IP in this proceeding should be incorporated into IP's cost of service study prior to performing the final class revenue allocation and determining the specific rates and charges in accordance with the overall resolutions of issues in this Order.

5. Allocation of Overall Revenue Requirement to Customer Classes

a. IP's Position

IP stated that the approved overall revenue requirement should be allocated among the customer classes using the approved cost of service study so as to achieve equalized class rates of return, with one exception. IP presently serves one customer

on a contract under SC 90, Contract Service. Under the terms of that contract, the pricing under the contract is exempt from being changed due to a general rate increase proceeding. Therefore, to the extent that the equalized rate of return approach would have resulted in a rate increase for the SC 90 customer, the incremental revenue that would have resulted from increasing rates to the SC 90 customer must be allocated among the other classes. (IP Ex. 7.10, pp. 6-7) For purposes of allocating the overall revenue requirement to the customer classes, IP utilized the following classes: (i) SC 51, Residential Gas Service; (ii) SC 63, (non-residential) Small Volume Firm Gas Service; (iii) SC 64, (non-residential) Intermediate Volume Firm Gas Service; (iv) SC 66, Seasonal Gas Service (this class is comprised of former SC 67 and SC 68, which SC 66 is replacing); (v) SC 65 and SC 76, Industrial Gas Service; and (vi) SC 90, Contract Service. SC 65, Large Volume Firm Gas Service, and SC 76, Transportation of Customer-Supplied Gas with Best Efforts Backup, were grouped together for revenue allocation purposes because they generally constitute the IP's industrial class, and customers can periodically switch between these two service classifications. (*Id.*, p. 6)

In response to the ALJ's request that the parties submit an attachment or attachments with their initial briefs showing their proposed allocations of the revenue requirement among the customer classes and their proposed rates and charges, IP provided IP Appendix A and IP Appendix B to its Initial Brief, each consisting of four schedules. The schedules were in format similar to exhibits previously submitted by IP witnesses Althoff and Jones. Each IP Appendix showed the allocation of this net revenue requirement (i.e., the overall revenue requirement net of miscellaneous revenues¹⁹) to the customer classes based on IP's cost of service study. Schedule 2, page 2, columns (2) and (7) of IP Appendix B showed that the maximum \$14,227,000 base rate increase defined by the Stipulation should be allocated as follows:

Class	Constrained Revenue Requirement Allocation	Revenue Increase Allocation
SC 51 (Residential)	\$ 94,367,237	\$ 5,272,995
SC 63 (Small Volume Firm)	\$ 24,961,155	\$ 4,951,857
SC 64 (Intermediate Volume Firm)	\$ 5,792,893	\$ 1,590,135
SC 66 (Seasonal)	\$ 1,140,930	\$ 536,190 ²⁰
SC 65/76 (Industrial)	\$ 9,886,510	\$ 1,875,747
SC 90 (Contract)	\$ 1,240,878	--

¹⁹Miscellaneous revenues include forfeited discounts (late payment charges), reconnect charges, gas service activation fees, equipment rentals, farm and lease income, non-sufficient check charges and certain charges for emergency service calls (IP Ex. 5.1, p. 9), and the accounting fee IP retains for billing, collecting and remitting municipal utility taxes. (IP Ex. 2.35, p. 26)

²⁰The actual net increase to SC 66 is \$245,490 due to a decrease in this class's PGA charges because these customers will be billed Rider B Commodity Gas Charges rather than Rider A Gas Charges. (IP Appendix B, Sched. 2, p. 2, col. (7))

Totals	\$137,389,604	\$14,226,923²¹
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IP took issue with Staff's proposed approach for allocating the final approved revenue requirement to the customer classes. Staff witness Lazare, in his rebuttal testimony, presented a proposed interclass revenue allocation based on a revenue requirement and rate increase for IP of \$144,969,000 and \$21,806,000, respectively, which reflected IP's rebuttal revenue requirement and rate increase proposal. (Staff Sched. 16.02) He also presented specific proposed rates and charges for the individual service classifications to recover this revenue requirement. (Staff Sched. 16.03) He then testified that if the final revenue requirement and rate increase amounts were lower than the values he used on Schedule 16.02, the rates developed in his Schedule 16.03 should be prorated down on an equal percentage basis to conform to the final approved revenue requirement. He asserted that re-running the cost of service study to allocate the final approved revenue requirement to the customer classes would require time and effort and contained the potential for errors, and that the incremental accuracy that would be achieved did not justify the attendant time and energy. (Staff Ex. 16.0, pp. 12-14) In Staff's Initial Brief, Staff provided schedules setting forth a proposed class revenue allocation and specific rates and charges for each service classification to recover the revenue requirement on Appendix A to the Stipulation, which was developed using Mr. Lazare's approach of reducing the rates and charges he had designed to recover IP's rebuttal revenue requirement by the percentage difference between the rebuttal revenue requirement and the Stipulation Appendix A revenue requirement.

IP stated that Mr. Lazare's percentage reduction approach is inappropriate, particularly given the significant difference between the revenue requirement for which Mr. Lazare presented a proposed allocation in his rebuttal testimony and the minimum and maximum revenue requirement amounts that will result in this case due to the Stipulation. (IP Ex. 7.30, pp. 13-14; IP Init. Br., p. 77) IP noted that Mr. Lazare's position may have been motivated by the fact that Commission rate orders typically provide for a three to five business day period following the utility's filing of its compliance tariffs for Staff to verify that the tariffs in fact comply with the order and produce the authorized revenue requirement and rate increase. IP noted that this should not be a concern in this case given the Stipulation, which defined the minimum and maximum revenue requirement and rate increase amounts, and the fact that the ALJ provided the opportunity to submit schedules showing the parties' proposals for class allocation of the minimum and maximum revenue requirements and specific rates and charges to recover them. (IP Init. Br., p. 77)

IP stated that Staff's approach is inappropriate, does not produce cost-based rates in accordance with the Commission's final determinations, and should therefore be rejected. As an example of the flawed outcome of Staff's approach, IP noted that its

²¹The actual net increase in total revenues is \$13,936,224 due to the decrease in the PGA charges to SC 66 because these customers will be billed Rider B Commodity Gas Charges rather than Rider A Gas Charges. (IP Appendix B, Sched. 2, p. 2, col. (7))

rebuttal presentation included full recovery of all Hillsboro-related costs but no allocation of storage-related costs to SC 76 customers, while the \$138,566,000 “Appendix A” revenue requirement excludes the revenue requirement associated with the Hillsboro base gas adjustment and the equity return on the non-used and useful (per Staff) portion of the Hillsboro investment. The “Appendix A” revenue requirement also reflects the reduction in revenue requirement resulting from applying the stipulated rate of return (8.18%) rather than IP’s proposed rebuttal rate of return (9.39%) to the entire storage field investment included in rate base. In short, IP stated, Staff’s approach reduces the rates in SC 76 due to reductions in a cost of service component that was not allocated to these customers in the first place. IP also pointed out that Staff’s approach reduces Facilities Charges, which are to be based on the costs of services, meters, regulators and other customer premises equipment and costs for customer billing and accounting, based on reductions in IP’s proposed overall revenue requirement, such as storage-related costs, that have nothing to do with customer premises facilities. (IP Ex. 7.30, pp. 13-14; IP Rep. Br., pp. 81-82)

IP stated that Staff’s approach would discard all the time and effort that the parties have devoted in this case to resolving cost of service study (and rate design) issues. IP expressed concern that Staff apparently did not believe that accurate class revenue allocation and rate design is worth the effort. Further, IP noted that while Staff witness Lazare purported to be overwhelmed by IP witness Jones’ two page discussion in rebuttal testimony of how to develop the final rates and charges to recover the final approved revenue requirement, the task is in fact not that hard. IP witness Jones testified that many of the steps he outlined to adjust prices to recover the final revenue requirement have been automated and can be implemented well within the compliance filing time normally ordered by the Commission. He testified that “I do not believe it is a waste of time to provide customers with accurate, cost-based prices that correspond to the final revenue requirement that the Commission approves.” (IP Ex. 7.30, p. 13)

IP responded to IIEC’s position that SC 65 and SC 76 should be treated separately, not together, for revenue allocation purposes. IP stated that although IIEC attempted to identify distinctions between the customers served on these two service classifications, from IP’s perspective they are not distinguishable. IP noted that, theoretically, all industrial customers could be served on either SC 65 or SC 76, and in fact customers are allowed to periodically switch between the two tariffs. (IP Ex. 7.19, p. 6) IP stated that the only practical distinction between the customers served on these tariffs is that the SC 65 customers want the ability to purchase system supply gas from IP if necessary, which SC 65 provides; however, SC 65 customers are also entitled to transport their own customer-supplied gas (like SC 76 customers) by electing transportation service on Rider OT, which many SC 65 customers have done. To ameliorate IIEC’s concerns on this topic, IP pointed out that its proposed rates and charges for SC 65 and SC 76 to recover the portion of the overall revenue requirement allocated to this class, as shown on IP Appendices A and B to IP’s Initial Brief, reflect several cost-based distinctions between SC 65 and SC 76, including: (i) separate Facilities Charges have been designed for SC 76 customers and for comparably-sized (load-wise) SC 65 customers; (ii) no storage costs have been allocated to SC 76 (IP Ex.

7.10, p. 21); (iii) the Delivery Charge has been eliminated for SC 76 because delivering gas to SC 76 customers does not cause IP to incur a volumetric delivery cost (IP Ex. 7.10, p. 21); and (iv) the SC 76 Demand Charges are lower than the SC 65 Demand Charges. (IP Rep. Br., pp.83-84)

IP also responded to BEAR's suggestion that the revenue increase allocated to SC 66 should be no higher than 50% more than the system average increase. IP pointed out that as shown on Schedule 2, page 2, columns (7) and (8) of IP Appendices A and B, IP's proposed revenue allocations to SC 66 in both the "low" and "high" revenue requirement scenarios exceed this limit, but IP's proposed percentage increase to the SC 66 class is modest in any event, i.e., approximately a 7% increase in total revenue (including PGA revenue) to be billed to this class. Therefore, BEAR's proposed limit for SC 66 is unnecessary. IP stated that in light of this relatively modest increase and the fact that IP's base rates have not been adjusted in eleven years, BEAR's assertion that the proposed increase for SC 66 was violative of "rate continuity" must be rejected. (IP Rep. Br., p. 85) IP also stated that if the Commission were to order a limit on the revenue increase for SC 66, it should be based the total class revenue including PGA revenue, not just base rate revenue. IP stated that this is especially important with respect to current SC 67 customers moving to new SC 66, since these customers will receive the benefit of lower PGA costs, as they will be subject to the Rider B Commodity Gas Charge instead of the Rider A Gas Charge which incorporates demand costs. (IP Ex. 7.30, p. 11; IP Init. Br., p. 78) IP also stated that if the Commission accepted Ms. Smith's suggestion, the SC 66 class would be charged less than its cost of service and therefore these customers would be subsidized by all other customers, without justification. (IP Init. Br., p. 78)

Similarly, IP rejected BEAR claims that under IP's proposed rate design, the "rate increase will fall very unequally on grain dryers." IP noted that as shown on IP Appendix B, Schedule 2, page 2, in the \$14,227,000 revenue increase scenario, IP's proposed class revenue allocation produces a 6.94% increase for SC 66 versus 6.23% for SC 63, 6.15% for SC 64 and 4.97% for SC 65/SC 76. IP stated that SC 66 is not receiving unequal treatment among the non-residential customers. IP noted that the proposed increase to SC 66 is less than 150% of the combined increase to the remainder of the non-residential class (SC 63, SC 64 and SC 65/SC 76), which is appropriate in light of the fact that SC 66 is an optional rate and customers electing service on it would otherwise (depending on the size of the customer) take service on SC 63, SC 64, SC 65 or SC 76. (IP Ex. 7.30, pp. 11-12) IP emphasized again that SC 66 will be an optional rate. No grain dryer will be required to take service on this rate. Grain drying customers can instead elect to take service on (depending on the customer's load size) SC 63, SC 64 or SC 65 (in each case in combination with Rider OT if desired) or SC 76. IP stated that proposed SC 66 offers significant benefits for seasonal use customers by eliminating demand charges and the Rider B Demand Gas Charge if the customer avoids using gas on days on which the temperature is projected to be 25% F or lower. IP's analysis showed that virtually all current SC 67 customers should benefit by taking service on SC 66 rather than on the firm tariff otherwise applicable to the customer. (IP Ex. 7.19, p. 26) However, those grain dryers that find

SC 63, SC 64, SC 65 or SC 76 to be more cost-effective than SC 66 for them can take service on the more beneficial rate. (IP Rep. Br., p. 86)

- b. Staff's Position**
- c. IIEC's Position**
- d. BEAR's Position**
- e. Commission Conclusion**

The Commission concludes that the class revenue allocation presented by Illinois Power in "IP Appendix B" to IP's Initial Brief in this proceeding is reasonable and should be adopted. IP's proposed revenue allocation is based on the specific overall revenue requirement and rate increase approved in this Order, and is the most complete and theoretically sound presentation available. Whatever the merits of Staff's "proration" approach might be in a more typical rate case, in this case the range of the potential final overall revenue requirement outcome was known with a high degree of certainty by the close of the hearings and thus an approach tailored to the potential outcome, as provided by IP, should be utilized.

With respect to IIEC's proposal that SC 65 and SC 76 should be treated as separate classes for purposes of the interclass revenue allocation, the Commission finds, based on the record, that IP has justified treating SC 65 and SC 76 as a single class for revenue allocation purposes.

The Commission rejects BEAR's arguments concerning the revenue allocation to the SC 66 class proposed by IP, as well as BEAR's proposal that the increase to SC 66 should be no more than 50% higher than the system average increase. The percentage increase to SC 66 produced by IP's allocation is not excessive, is not violative of rate continuity considerations, and in fact is reasonably consistent with the percentage increases to the other non-residential classes. The Commission agrees with IP that it is appropriate to take into account the benefit to seasonal gas customers electing service on SC 66 of not being billed the Rider B Demand Gas Charge in calculating the overall revenue impact on these customers. The Commission emphasizes that SC 66 is an optional rate intended to provide benefits to seasonal use customers based on their usage characteristics, that no customer will be required to take service on SC 66, and that if a customer eligible for SC 66 finds that it can obtain gas service at lower cost on the customer's otherwise applicable rate (such as SC 63, SC 64 or SC 65), the customer will be free to take the lower-cost rate.

6. Issues Associated with Vendor-Supplied Cost of Service Model Used by AmerenIP

- a. Staff's Position**

b. IP's Position

IP responded to Staff witness Lazare's concerns about IP's use of a copyright protected, vendor-supplied cost of service model and his proposal that the Commission should order AmerenIP to present a non-copyright-protected cost of service study in future gas rate cases. IP stated that its cost of service study was presented in this case consistent with the applicable rules. Specifically, 83 Ill. Admin. Code Section 285.5110 describes the requirements for an embedded class cost of service study to be submitted with a gas utility's rate case. IP pointed out that Mr. Lazare never claimed that IP's cost of service study is not in accord with such rules. (IP Init. Br., p. 79) As to Mr. Lazare's complaint that Staff and others are required to execute a confidentiality agreement in order to access certain formulas in the model, IP noted that Part 285 acknowledges that a utility may be prevented from providing a working model that it obtained from an outside vendor by virtue of the utility's agreement with that vendor. In that event, the utility is permitted to have its vendor enter into an agreement with case participants to provide a working copy of the model to be used for a fixed and limited time period. IP witness Althoff explained that Mr. Lazare requested a copy of the IP model about six weeks after the case was filed, which was 25 days after other Staff members had sent their initial data requests, and the model was provided after Staff signed a confidentiality agreement. (IP Ex. 5.6, p. 19; IP Ex. 5.10, p. 12)

IP also pointed out that cost of service models supplied by the same vendor that supplied IP's gas cost of service model have been used by IP in the past, this same vendor has required a confidentiality agreement to be signed and, in fact, Mr. Lazare was the Staff witness in IP's 2001 delivery service tariff ("DST") case, Docket 01-0432, where a confidentiality agreement with this vendor was required to be signed. (Tr.121-122) IP noted that after IP's DST case in 2001, the Commission engaged in a rulemaking to consider changes to Part 285 (Docket 02-0509). Mr. Lazare participated in the rulemaking on behalf of Staff. (Tr. 123) In that rulemaking, Part 285, including Section 285.5110, was open for discussion and changes. IP emphasized that there were three changes made to that section; two of the three suggestions were made by IP, and each was agreed to by Staff. In particular, IP recommended specific language clarifying what is meant by "black box" and Staff agreed with IP's suggestion to include the phrase "i.e., formulas may be hidden to prevent viewing." (Order in Docket 02-0509 (Mar. 26, 2003), p. 26) IP stated that if Staff had any complaints with regard to the use of an outside vendor, the use of a confidentiality agreement, whether a cost of service study may have hidden formulas, and so forth, and in particular deriving from Mr. Lazare's experience in these areas with IP's vendor-supplied cost of service model in the 2001 IP DST case, the time to address these matters was in the context of that rulemaking, and not in this rate case. (IP Init. Br., pp. 79-80)

IP emphasized that in fact Staff could review all the inputs of IP's model, make changes and execute alternative scenarios. (IP Ex. 5.6, p. 19) Mr. Lazare, and any other parties that executed a confidentiality agreement, were provided a fully functioning copy of the cost of service study identical to the model IP used. (IP Ex. 5.10, p. 12)

IP also noted that both the gas cost model it used in this case and its electric cost model in the DST case were developed and supplied by Management Applications Consulting, Inc., whose cost of service models have been successfully employed to perform cost studies in some 19 states, including Illinois, during the past few years. (IP Ex. 5.10, pp. 13-14) IP also pointed out that use of a vendor-supplied model was a cost-effective approach for IP and enabled it to avoid having to devote resources to creating and maintaining its own model. IP stated that any vendor-supplied model of reasonable quality could be expected to be copyright protected. (IP Rep. Br., p. 88)

IP offered to engage in a collaborative effort with Staff and any other interested parties following the conclusion of this rate case to address ways of mitigating Mr. Lazare's concerns while satisfying vendor requirements with respect to maintaining confidentiality of the cost of service model. (IP Ex. 5.10, p. 14-15) However, IP urged the Commission to reject Mr. Lazare's proposal that IP be required to utilize a non-copyright-protected cost of service model in future cases. (IP Rep. Br., p. 88)

c. Commission Conclusion

The Commission finds, based on the record, that Illinois Power made its cost of service model available to Staff and other parties in this case in conformance with the requirements of recently-amended 83 Ill. Administrative Code Part 285, in particular Section 285.5110. Further, IP's actions in this regard were consistent with what has transpired in previous cases with respect to the use and availability of a vendor-supplied, copyright-protected cost of service study. Additionally, adequate opportunity was provided to interested parties in this case, consistent with the Commission's rules, to access an unrestricted version of IP's cost of service model. Particularly in light of the fact that the types of concerns raised by Staff were addressed in the last rulemaking to amend Part 285, which was completed fairly recently, the Commission finds no reason to reject use of IP's cost of service model in this case, or to require IP to adopt a different model in the future. The Commission encourages Staff and other interested parties to participate in the collaborative process that IP has offered following the conclusion of this case. However, the Commission finds no basis to impose any other requirements on IP.

B. Development of Rates and Charges

1. AmerenIP's Position

Schedule 3 to each of IP Appendix A and IP Appendix B to IP's Initial Brief showed IP's proposed rates and charges in the individual service classifications for the \$11,336,000 and \$14,227,000 base rate revenue increase scenarios, respectively. IP witness Jones described the basis on which IP designed its proposed rates and charges for the various service classifications. (IP Ex. 7.10, pp. 8-24) The starting point was the allocation of the overall revenue requirement to the customer classes on an equalized rate of return basis using the cost of service study. Within each class, customer costs (i.e., the costs associated with serving a customer regardless of whether any gas is

used, including the meter, service line, regulator, recurring meter expenses and administrative costs of servicing the account), as developed in the cost of service study, were used to develop the proposed Facilities Charges. (*Id.*, p. 8) Delivery Charges and, for the service classifications on which larger-use non-residential customers are served, Demand Charges, within each service classification, were used to recover the remaining fixed costs associated with the customer's use of IP's distribution system. (*Id.*, p. 8)

IP is generally proposing increases to the existing rate elements in its gas tariffs without significant rate design changes from the current tariffs. The following paragraphs summarize highlights IP's proposed rate design, particularly with respect to changes from the rate design in IP's current gas rates.

SC 51 (Residential) and SC 63 (non-residential Small Volume Firm). The Delivery Charges in present SC 51, Residential Gas Service, and SC 63, (non-residential) Small Volume Firm Gas Service, are both declining block rates. IP proposes that the Delivery Charges in SC 51 and SC 63 become single, flat rates applicable to all therms delivered, because all customer costs are to be recovered through the Facilities Charges in these service classifications. (IP Ex. 7.10, pp. 10, 12) IP noted that there was no objection to this proposal. (IP Init. Br., p. 82)

SC 65 (non-residential Large Volume Firm) and SC 76 (Transportation of Customer-Supplied Gas). For SC 65, Large Volume Firm Gas Service, and SC 76, Transportation of Customer-Supplied Gas with Best Efforts Backup, IP developed separate Facilities Charges for each service classification, but the transmission and distribution costs for SC 65 and SC 76 were combined to establish the cost bases for the high pressure and low pressure Demand Charges. The low pressure Demand Charge is based on the cost for the delivery assets (i.e., facilities operated at equal to or less than maximum allowable operating pressure ("MAOP") of 60 psig) required to get to the customer's location plus the cost for transmission delivery assets (i.e., facilities operated at a MAOP greater than 60 psig). The cost basis for the high pressure Demand Charge excludes the cost for the low pressure assets since customers served at high pressure do not utilize IP's low pressure system. Additionally, the SC 65 Delivery Charge recovers a portion of demand costs. (IP Ex. 7.10, pp. 13-14)

The SC 76 Facilities Charges for customers that would otherwise be served on SC 63 or SC 64 if they took firm supply gas service from IP are equal to the applicable Facilities Charges under those service classifications. (IP Ex. 7.10, pp. 19-20; IP Ex. 7.19, pp. 4-5) However, for customers with an average daily usage of 1,000 therms or more, separate Facilities Charges are provided in SC 76 for customers with an average daily usage of up to 10,000 therms and customers with an average daily usage of 10,000 therms or more. (IP Ex. 7.10, p. 20; IP Ex. 7.19, pp. 5-6) IP noted that Staff witness Lazare reviewed the bases for IP's proposed SC 76 Facilities Charges and found them to be reasonable. (Staff Ex. 16.0, pp. 9-10; IP Init. Br., p. 83) Additionally, IP is eliminating the Delivery Charge in SC 76 because delivering gas to SC 76 customers does not cause IP to incur a volumetric delivery cost. (IP Ex. 7.10, p. 21)

SC 66 (Seasonal Gas Service). SC 66, Seasonal Gas Service, is a new, optional tariff intended to replace existing SC 67, Firm Gas Grain Drying Service, and existing SC 68, Seasonal Gas Asphalt Service. Customers that might find SC 66 attractive will also have the option to take service on any other service classification for which the customer qualifies (i.e., firm supply service on SC 63, SC 64 or SC 65, or transportation service on SC 76). (IP Ex. 7.19, p. 19; IP Init. Br., p. 83) IP initially proposed that SC 66 would include separate Facilities Charges for customers with a Maximum Daily Quantity ("MDQ") or actual use less than a maximum of 1,000 therms per day and for customers with a MDQ or actual use equal to or greater than 1,000 therms per day. (IP Ex. 7.10, pp. 17-18) However, in response to customer impact concerns expressed by BEAR witness Smith, IP developed Facilities Charges for SC 66 customers delineated between customers served from facilities with MAOP equal to or less than 60 psig and customers served from facilities with a MAOP greater than 60 psig, and with separate Facilities Charges within each of these categories for small, medium and large customers. (IP Ex. 7.19, pp. 8-13) IP stated that it is proposing a menu of six Facilities Charges in SC 66 to better match cost recovery and pricing to the specific characteristics of the individual customers served on this tariff and the facilities that serve them. (IP Init. Br., pp. 83-84) (Issues relating the SC 66 Facilities Charges, as well as the overall price level and competitiveness of this rate, are addressed in greater detail in Section VIII.A below.)

SC 66 customers that purchase system supply gas from IP will be billed the Rider B Gas Commodity Charge under IP's PGA. (IP Ex. 7.10, p. 16) IP stated that this feature of SC 66 will provide a benefit particularly to grain dryers currently served on SC 67, since SC 67 customers are billed the Rider A Gas Charge, which recovers pipeline demand-related gas supply costs as well as commodity costs, and therefore typically is higher than the Rider B Gas Commodity Charge. (IP Ex. 7.19, p. 22; IP Init. Br., p. 84)

Additionally, under SC 66, customers will be billed a Delivery Demand Charge and the Rider B Demand Gas Charge based on gas consumed on days when average temperatures are forecasted to be at or below 25 degrees Fahrenheit. IP originally proposed that these demand charges be applicable for usage consumed on days when the temperature is forecast to be at or below 32 degrees F., but modified this provision to 25 degrees F. during the course of the case in response to concerns expressed by BEAR. (IP Ex. 7.10, p. 18; IP Ex. 7.30, pp. 9-10) IP noted that BEAR's Initial Brief indicated acceptance of the 25 degree F. threshold. (IP Rep. Br., p. 90) However, SC 66 customers that have provided a contribution to IP for a delivery system improvement to expand capacity to serve the customer's load at times of system peak will be allowed to contract with IP for a Winter Delivery Allowance, which will be an amount of gas the customer can use on days when the temperature falls below the temperature criterion, without incurring a Delivery Demand Charge. (IP Ex. 7.10, pp. 16-18) Such customers will, however, be billed the Rider B Gas Demand Charge for gas consumed on days when the temperature is forecast to be below 25 degrees F; this is because the Rider B Gas Demand Charge recovers gas supply costs, not delivery system costs. (*Id.*)

Development of final proposed rates and charges. As noted above, Schedule 3 in each of IP Appendix A and IP Appendix B to its Initial Brief shows IP's proposed rates and charges for each service classification under the \$11,336,000 and \$14,227,000 base rate increase scenarios, respectively, along with a comparison to the current rates and charges. IP witness Jones explained how the final rates and charges should be established to produce the final revenue requirement allocated to each customer class, if the final revenue requirement is less than the revenue requirement proposed by IP in rebuttal (which both the minimum and maximum revenue increases defined by the Stipulation will be). (IP Ex. 7.19, pp. 28-29) IP employed these considerations in developing the proposed rates and charges shown on Schedule 3 of IP Appendix A and IP Appendix B. (IP Init. Br., pp. 85-86)

As was the case with respect to the class revenue allocation, IP disagreed with Staff witness Lazare's position that if the final approved revenue requirement is lower than the revenue requirement presented by IP in rebuttal, which Mr. Lazare used to design the proposed rates he presented in his rebuttal testimony, then each of his proposed rates and charges should be adjusted downward on an equal percentage basis to achieve the approved revenue requirement. IP stated that Mr. Lazare's approach is inappropriate and would disregard the considerable effort the parties to this case have devoted to revenue allocation and rate design issues. (IP Ex. 7.30, pp. 13-14; IP Rep. Br., p. 89)

2. Staff's Position

3. IIEC's Position

4. BEAR's Position

5. Commission Conclusion

For similar reasons to those discussed in Section VII.A.5 of this Order concerning allocation of the overall revenue requirement to the customer classes, the Commission concludes that the specific rates and charges proposed by Illinois Power and presented in IP Appendix B to IP's Initial Brief in this proceeding are reasonable and should be adopted. In the circumstances of this proceeding, adoption of IP's proposed rates and charges, which were specifically designed to recover the final approved revenue requirement and rate increase in this proceeding, are preferable to the rates and charges produced by Staff's "proration" approach.

The issues raised by BEAR with respect to the SC 66 Facilities Charges are addressed in Section VIII.A of this Order, below.

VIII. TARIFF TERMS AND CONDITIONS

A. Service Classification 66

1. AmerenIP's Position

AmerenIP proposes to implement a new tariff, SC 66, Seasonal Gas Service, directed toward providing cost-based, competitive service to seasonal use customers such as grain dryers and asphalt plants. SC 66 is an optional service intended to be available to all present SC 67 (grain drying) and SC 68 (asphalt) customers (as well as any other customers that find this tariff beneficial based on their usage characteristics). SC 67 and SC 68 would be canceled. IP witness Jones explained the principal features of proposed SC 66. (IP Ex. 7.10, pp. 15-18) (Certain rate provisions of SC 66 are also discussed in Section VII.B of this Order, above.) However, as agreed in the latter stages of this proceeding, SC 66 will not be implemented until the first day of the month in which AmerenIP is migrated to the other Ameren utilities' customer service system. Until that time, existing SC 67 and SC 68 will remain in effect. (IP Ex. 8.6, pp. 28-31; IP Ex. 8.14, p. 10; IP Init. Br., p. 91)

IP responded to BEAR witness Smith's testimony that the Facilities Charge for SC 66 customers should be no more than \$400, with the remaining customer-related costs allocated to all units charged, and to her concerns regarding the threshold point for the Facilities Charges allocated to SC 66 customers as proposed in IP's direct case filing. IP witness Jones testified that Ms. Smith's simple averaging recommendation failed to take into account the differing cost characteristics of customers within this seasonal gas use class. He noted that Ms. Smith's Exhibit LS-3 showed that there are 16 different meter types serving SC 67 and 68 customers. (IP Ex. 7.19, p. 6) IP noted that different meter types mean different meter costs, and these cost differences should have some bearing on the overall level of the Facilities Charges. (IP Init. Br., p. 88) However, IP revisited its proposed SC 66 Facilities Charges taking into consideration the maximum demand for the customer as well as the data shown on BEAR Exhibit LS-3. IP witness Jones explained that the list of meter types and costs can be organized in three general groupings. The first group is meters with an installed cost of \$8,500 or less, the second group is meters that cost approximately \$20,000 to install, and the third group consists of meters that cost approximately \$40,000 to install. He then considered hourly and daily maximum capabilities for each grouping to be matched against the expected peak hourly demand of a customer. Taking into consideration the MAOP and capacity associated with both low pressure and high pressure mains, Mr. Jones developed a revised set of Facilities Charges for SC 66 that would be delineated between customers served from systems with a MAOP equal to or below 60 psig and those served from systems with a MAOP above 60 psig. He then developed a cost basis for the proposed SC 66 Facilities Charge based on the two new usage categories he developed, each of which would have three different levels of charges for small, medium, and large SC 66 customers. (IP Ex. 7.19, pp. 8-12) IP noted that although BEAR witness Smith, in her rebuttal testimony, continued to raise overall objections to the level of the proposed SC 66 rates, she did not object to the cost method employed by Mr. Jones or his underlying analyses. (IP Init. Br., pp. 88-89)

In his surrebuttal testimony, AmerenIP witness Jones, responded to Ms. Smith's contentions regarding the use of differing meter cost values. He pointed out that when the meter cost values in BEAR Exhibit LS-7 are substituted for the previously-used meter cost

values found on page 1 of IP Exhibit 7.21, the impact on the proposed customer cost for serving small, medium and large size customers is relatively minor. IP emphasized that the correct meter cost should be used to develop the cost basis for the rates and that was what IP used. (IP Ex. 7.30, pp. 2-3; IP Init. Br., p. 89))

IP also argued that BEAR's argument that the Facilities Charges for SC 66 should be set equal to the Facilities Charge that the SC 66 customer would pay if taking service on the otherwise applicable IP firm tariff (e.g., SC 63, 64 or 65) should be rejected. IP noted that on page 10 of its Initial Brief BEAR showed a comparison of the proposed Facilities Charges for SC 66 to the proposed Facilities Charges for SC 63, SC 64 and SC 65, including the "Small Volume Standard" Facilities Charge for SC 63 of \$25. IP pointed out, however, that none of the grain dryers currently served on SC 67 would qualify for the "Small Volume Standard" SC 63 Facilities Charge, because of their requirements for higher pressure delivery, and SC 67 customers who qualified for SC 63 service would have to take Non-Standard service (i.e., delivery pressure greater than 12 inches water column) for which the proposed Facilities Charge is \$90. IP stated that of the 79 grain dryers taking service on SC 67 in 2003, only 6 were small enough to have taken service on SC 63. (IP Ex. 7.29) IP also explained that the average meter-related embedded cost for all SC 67 and SC 68 customers is close to the value for SC 65. (IP Ex. 7.30, p. 8; IP Ex. 7.21) Finally, IP noted that its proposed SC 66 Facilities Charges to recover the Stipulation revenue requirement (small, \$375, medium, \$725, large, \$1,500) are different than the SC 66 Facilities Charges shown in BEAR's brief (see Schedule 3 to IP Appendices A and B to IP's Initial Brief). (IP Rep. Br., p. 91)

IP argued that BEAR wants the best of both worlds: a rate with no demand charges if the customer does not use gas when the temperature is below 25 degrees, coupled with the lower Facilities Charges of IP's otherwise applicable, and more broadly used, tariffs. IP explained that given that each customer cannot be charged a Facilities Charge equal to the specific costs of the facilities installed at its premises (IP Ex. 7.19, p. 6) but rather that customers must be grouped for purposes of designing service classifications, the Facilities Charges for each of SC 63, SC 64, SC 65/SC 76 and SC 66 are based on the costs of the customer-related facilities that would be installed to serve the sizes of customers that take service on each tariff, as defined by the tariff's eligibility requirements. IP stated that the customer-related facilities installed to serve customers expected to take service on SC 66 are larger, in part because (as explained below) these customers require delivery of larger volumes of gas during a very short period of time. Because IP is offering a tariff tailored to the unique usage characteristics of the seasonal use customers, it has also designed cost-based Facilities Charges for that tariff based on the cost characteristics of the facilities typically installed to serve customers on that tariff, which results in higher Facilities Charges for SC 66 than for SC 63 and SC 64. IP stated that if a customer elects to take service on SC 66, an optional rate, and receive the benefit of paying no demand charge and no Rider B Demand Gas Charge due to the customer's seasonal use characteristics, the customer can reasonably be expected to pay a Facilities Charge that reflects the costs of the facilities installed to serve seasonal use customers. (IP Rep. Br., pp. 91-92)

IP stated that seasonal use customers tend to have higher meter costs compared to those that would apply for the otherwise applicable firm service rate. The availability provisions for SC 63, SC 64 and SC 65 are based on the customer's average use within each of the past twelve billing periods. For customers on these tariffs, the average use per day is an accurate indicator of the customer's daily peak demand, which dictates the type of metering facilities needed to measure the customer's use. However, for many seasonal use customers, especially grain dryers, a monthly use per day average does not adequately capture the customer's required peak, but rather understates it. At the peak of the harvest, many grain dryers consume gas at a very high rate for up to two weeks and significantly less during the rest of the billing period. Thus, IP stated, due to this usage pattern, metering facilities commonly used to serve the average SC 63 and SC 64 customers (who use gas more evenly throughout their peak months) are often too small to serve a grain dryer with the same average use per day. Rather, grain dryers often require larger, more expensive metering. IP stated that its proposed Facilities Charges for SC 66 reflect these cost differences. (IP Ex. 7.30, pp. 8-9)

IP stated that the discussion at page 11 of BEAR's Initial Brief, based on meter cost data provided on BEAR Cross Exhibit 1, is not an informative or useful comparison of meter costs among the service classifications. IP stated that the costs referred to in BEAR's brief are only the current costs of the meter itself. BEAR did not discuss the meter installation costs, which are also shown on BEAR Cross Exhibit 1, and which can increase disproportionately to the meter cost as the size of the meter increases (for example, IP pointed out, the meter type costing \$2,767 requires 79 manhours to install while the meter type costing \$4,094 requires 160 manhours to install). Also, BEAR did not discuss any other customer-related costs that would be included in the development of the Facilities Charges. (IP Rep. Br., p. 94)

IP stated that BEAR was incorrect in asserting that IP determined Facilities Charges using a mixture of embedded costs and current costs. IP only allocated actual embedded costs to the customer classes. However, this allocation was made using the current replacement costs of facilities that would be installed to serve customers in the various classes as one of the bases for the allocator. (IP Ex. 5.1, pp. 7-8) IP stated that there is nothing amiss about this allocation method; to the contrary, it is frequently used. IP pointed out that BEAR witness Smith testified that "It is customary to use current costs for meters, etc., to develop weighted allocators, because it is usually assumed that current cost can serve as a reasonable proxy for historic costs." (BEAR Ex. 2, p. 7) IP stated that current or replacement cost has frequently been used as the basis for allocating historic distribution costs throughout the utility industry. (IP Ex. 5.10, p. 11) In fact, IP used this method in its last two delivery services cases, Dockets 99-0120 & 99-0134 (Cons.) and 01-0432, for allocating meters as well as services, and the Commission approved the use of this method. (See *Illinois Power Company*, Docket 01-0432, Order (Mar. 28, 2002), pp. 59-61.) IP stated that, in summary, it used an accepted, Commission-approved method to allocate customer costs and, contrary to BEAR's assertion, there is no need for IP to rerun its cost of service study to allocate customer-related costs on a different basis. (IP Rep. Br., pp. 92-93)

IP stated that the Facilities Charges it is proposing for optional SC 66 were developed through a detailed analysis to match meter costs to the usage and meter type characteristic of customers expected to take service on this rate. IP stated that the proposed SC 66 Facilities Charges are founded on a proper allocation of meter and services costs to the customer classes. The total embedded cost of meters that was allocated to SC 66 was then allocated into three groups within SC 66 – small, medium and large. (IP Ex. 7.30, p. 3) IP witness Jones described at length the process by which IP developed the three meter size groups within SC 66, based on three categories of maximum daily demand, or MDQ. For customers served from systems with MAOP of 60 psig or less, those three groupings are less than 3,250 therms per day, 3,250 to 7,000 therms per day, and over 7,000 therms per day; while for customers served from systems with MAOP greater than 60 psig, the three groupings are less than 6,700 therms per day, 6,700 to 19,000 therms per day, and over 19,000 therms per day. (IP Ex. 7.19, pp. 7-12) Of the 79 grain dryers currently served on SC 67, 48 would be in the “small” category (\$375 Facilities Charge), 23 would be in the “medium” category (\$725 Facilities Charge), and eight would be in the “large” category (\$1,500). (*Id.*, p. 12)

AmerenIP witness Jones responded to BEAR witness Smith’s contention that the SC 66 rates would result in grain drying customers switching to propane. He pointed out that prior to IP’s last gas rate case, grain drying customers took service under SC 65, and that SC 67, a special tariff for grain dryers, was proposed and implemented to alleviate that concern. (IP Ex. 7.30, pp. 3-4) He also explained that grain drying customers switching to propane was unlikely because natural gas service under proposed SC 66 is competitively superior to propane for nearly all of AmerenIP’s existing SC 67 (grain drying) customers. Only a handful of these customers, with little or no gas use, would be better off on propane service. Mr. Jones used gas costs from the September and October 2003 time periods in this comparison, but also showed that commodity costs for propane and natural gas tend to be highly correlated and provided cost data for 2002, 2003 and year to date 2004 to demonstrate this.. (IP Ex. 7.19, pp. 24-25; IP Ex. 7.28; IP Ex. 7.30, p. 4; IP Ex. 7.32)

Specifically, IP Exhibit 7.28 sponsored by Mr. Jones presented a comparison of the cost to take gas service from IP on SC 66 to the cost of using propane for each of the 79 grain drying customers. IP noted that BEAR never rebutted this customer-by-customer analysis with one of its own. IP Exhibit 7.28 showed that only seven of the 79 customers would realize a lower cost by switching to propane. For six of those seven customers, the savings for switching to propane is less than \$4800 per year. Further, Mr. Jones explained that the analysis on IP Exhibit 7.28 (i) does not include the cost to the customer to purchase or rent a propane storage tank or tanks, and (ii) is based on IP’s rebuttal revenue requirement rather than the lower, maximum possible revenue requirement resulting from the Stipulation. (IP Ex. 7.19, pp. 24-25; IP Ex. 7.28) It also does not take into account the possibilities that (i) a grain drying customer could buy gas from a third party supplier at lower cost than IP’s PGA, and (ii) SC 66 being an optional rate, a grain dryer could obtain gas service from IP at lower cost under the customer’s otherwise applicable firm tariff. (IP Rep. Br., p. 95)

IP also responded to Ms. Smith's assertion that a customer taking service under SC 66 may pay more than a customer taking service under SC 67 or SC 68. IP emphasized that Ms. Smith ignored that SC 66 is an optional service. IP stated that if a grain drying or asphalt customer believes there are other rates more cost beneficial than SC 66 (e.g., SC 63, SC 64 or SC 65), the customer can take the other tariff. IP also noted that Ms. Smith ignored the fact that a customer taking service under SC 66 will be assessed only the Rider B Commodity Gas Charge, and not the Rider B Demand Gas Charge (unless the customer uses gas on a day when the temperature is below the temperature threshold). In contrast, customers on present SC 67 are charged the higher Rider A Gas Charge which incorporates both pipeline demand-related and commodity-related gas costs and is usually \$.05 to \$.06 per therm higher than the Rider B Commodity Gas Charge. (IP Ex. 7.30, pp. 5-6; IP Init. Br., p. 90)

Finally, IP responded to BEAR witness Smith's argument that AmerenIP's rates for grain dryers should be like those of AmerenCIPS and AmerenCILCO. IP pointed out that the AmerenCIPS and AmerenCILCO distribution rates are based on those utilities' respective costs of service, as should be the case for IP's rates. IP again emphasized that in making this comparison, Ms. Smith continued to ignore the full and complete impact of SC 66 on customers' gas costs as well as their distribution costs (as described above). IP witness Mr. Jones explained that the SC 66 delivery charge offers a substantial discount over these other applicable firm service rates. (IP Ex. 7.30, pp. 7-8; IP Init. Br., pp. 90-91)

IP concluded that all of BEAR's concerns regarding proposed SC 66 were without merit, and that the Commission should approve this new optional service for seasonal use customers with the rates, terms and conditions proposed by IP.

2. BEAR's Position

3. Staff's Position

4. Commission Conclusion

Based on its review of the record and the arguments of the parties, the Commission concludes that the rate design and terms and conditions of SC 66 as proposed by Illinois Power are reasonable and should be approved. First, the Commission notes that the record reflects agreement between IP and BEAR that under SC 66, 25 degrees Fahrenheit should be the temperature threshold at which SC 66 customers would be billed a demand charge and the Rider B Demand Gas Charge if they consume gas. That is, the SC 66 customer would be billed these demand charges if it consumes gas on a day when the temperature is forecast to be below 25 degrees F. (unless the customer has a Winter Delivery Allowance under the terms of SC 66 and only consumes gas within that allowance).

Based on the record, the Commission rejects BEAR's arguments concerning the level of the SC 66 Facilities Charges, including BEAR's position that an SC 66 customer should pay the same Facilities Charge it would pay on the customer's otherwise

applicable IP firm tariff. The record shows that IP's proposed Facilities Charges were developed using an appropriate cost of service and rate design process, and that seasonal gas customers such as those expected to be served on SC 66 require larger and therefore more costly customer-related facilities than those required by similar customers on SC 63, SC 64 and SC 65. In summary, the record shows that the Facilities Charges developed by IP for SC 66 properly reflect the cost characteristics of the facilities needed to serve the customers likely to take service on this tariff and for whom it has been designed. Because of the ability to avoid demand charges due to the seasonal nature of their use, SC 66 should be beneficial overall to these customers. However, the Commission emphasizes again that SC 66 is an optional rate, and that if a customer otherwise eligible for SC 66 determines that it can obtain gas service at lower cost on an otherwise applicable IP tariff, the customer will be free to take the more cost-beneficial tariff.

Finally, as agreed by IP, SC 66 should not go into effect until the first day of the month in which AmerenIP is migrated to the new Ameren customer service system. Until that time, existing SC 67 and SC 68 shall remain in effect.

B. Transportation Tariffs - Service Classification 76 and Rider OT

1. Daily Balancing and Cashout

a. IP's Position

AmerenIP is proposing to implement daily balancing with daily cash-out provisions for SC 76 customers. These provisions will require the SC 76 customer to nominate the volume of gas to be delivered to an interconnection point, which nomination is confirmed by the customer's final pipeline transporter. For each day, actual deliveries to the customer will be compared to the customer's nomination. The resulting imbalance will be used to determine a daily cash-out charge, assuming the imbalance is outside the daily deadband. The Chicago city gate index price will be used in calculating the cashout amount. The cashout amount would vary based on the extent of the over- or under-delivery. (IP Init. Br., pp. 91-92) IP witness Blackburn testified that the daily balancing and cashout provisions were needed to ensure appropriate flexibility to AmerenIP for the benefit of its sales customers with regard to the use of IP storage facilities. Otherwise, SC 76 customers are effectively able to use storage throughout the month, even though their rates do not incorporate any allocation of storage costs. (IP Ex. 8.1, pp. 8-9)

Staff witness Charles Iannello testified in support of implementing daily balancing and cashout provisions for SC 76 customers, conditioned upon adoption of a modified daily cashout schedule he proposed, the implementation of a group balancing service by IP, and implementation of steps whereby IP would make daily usage data available to customers on a more timely basis. (Staff Ex. 8.0, p. 11) IP agreed to the conditions that Staff witness Iannello proposed for the implementation of daily balancing and cashout. Specifically, IP agreed to the daily imbalance cashout schedule proposed in Mr. Iannello's direct testimony, except that IP proposed that the customer's net accumulated daily

imbalances within a 20% deadband would be cashed out at the end of the billing period (i.e., monthly). As discussed in Section VIII.B.2 of this Order, below, IP also agreed to the implementation of a group balancing service. Further, as discussed in Section VIII.B.3 below, IP agreed to install advanced metering and communication equipment at SC 76 customers' premises to record daily usage and to make the daily usage information available electronically to the customer. (IP Ex. 8.6, pp. 2-3)

IP noted that IIEC initially took issue with IP's proposed daily imbalance and daily cashout provisions, but identified a number of conditions that would have to be implemented for daily balancing and cashout to be reasonable acceptable. IP noted that it agreed to Staff's daily imbalance cashout schedule which affords transportation customers greater flexibility than did IP's original proposal, including adopting a 20% deadband within which no daily cashout occurs, and agreed to provide a group balancing service. In addition, IP agreed to the installation of advanced metering equipment and communications equipment that would permit customers to access daily usage information on a timely basis (within four to six hours after the end of the 24-hour "gas day", see Tr. 41-42). IP stated that by the end of the case, the specific steps that IIEC believed should be implemented in order to make daily balancing and cash out acceptable had been agreed to by AmerenIP, as IIEC witness Mallinckrodt acknowledged. (See Tr. 225-232) (IP Init. Br., pp. 93-94)

AmerenIP noted that the new daily balancing and cashout provisions will not go into effect until (i) AmerenIP is prepared to implement its group balancing service (discussed in Section VIII.B.2 below) and (ii) AmerenIP has installed the advanced metering and telecommunications equipment for SC 76 customers, to enable those customers to obtain their daily usage information within four to six hours after the end of the gas day. None of these provisions will be implemented until the first day of the month in which AmerenIP is migrated from its current customer accounting and billing system to the customer service system used by the other Ameren utilities. (IP Ex. 16.1, pp. 2-3; IP Ex. 8.6, pp. 29-31; IP Ex. 8.14, p. 10)

- b. Staff's Position**
- c. IIEC's Position**
- d. CNE-Gas Position**
- e. Commission Conclusion**

Based on its review of the record, the Commission concludes that IP's proposed balancing and cashout provisions for SC 76, as modified by IP in rebuttal in response to the suggestions of Staff and other parties, are reasonable and should be adopted. At this point in the proceeding there does not appear to be any objection to the modified balancing and cashout provisions. However, as agreed by IP, these new provisions should not go into effect until the effective date of IP's group balancing tariff, as

discussed in the next section of this order. Until that time, the existing balancing and cashout provisions should remain in effect.

2. Group Balancing Tariff

In response to other parties' initial concerns about IP's daily balancing and cashout proposal, AmerenIP committed to implement a group balancing service (sometimes referred to as a supplier aggregation tariff). A group balancing service would allow transportation customers to aggregate their loads and assist the customers in minimizing and avoiding both daily and monthly imbalances and associated cashout requirements. AmerenIP is willing to implement a group balancing service for AmerenIP's SC 76 and Rider OT customers similar to AmerenCIPS' Rider G, Group Balancing Service, if AmerenIP's daily balancing and daily cashout proposals (as IP modified those proposals during the course of the case) are accepted. (IP Ex. 16.1, p. 2) Implementation of the group balancing service will occur on the first day of the month in which AmerenIP's current billing system is converted to the customer service system used by the other Ameren utilities. The current best estimate as to when AmerenIP will be migrated to the Ameren customer service system is October 2005. (IP Ex. 8.14, p. 10) This will allow time for AmerenIP to modify the programming, contracts, forms and procedures developed for AmerenCIPS' Rider G, in conjunction with AmerenIP's SC 76 and Rider OT transportation rates. Additionally, IP's daily balancing and cashout provisions would not go into effect until the group balancing service goes into effect. (IP Ex. 16.1, pp. 2-3)

In response to CNE Gas's recommendation that AmerenIP be required to implement the group balancing service no later than September 1, 2005, and to file its proposed tariff no later than 60 days prior to that date, AmerenIP agreed to post the tariff 45 days prior to the anticipated effective date. However, as explained by AmerenIP witness Anderson, the current IP billing system is not programmed to handle the group balancing service. IP argued that it would be a waste of time and resources to modify the current legacy IP billing system to accommodate the group balancing service when within only a few more months, at most, AmerenIP will be converted to the Ameren billing system. (IP Ex. 16.3, pp. 4-5; IP Ex. 8.6, pp. 30-31; IP Ex. 8.14, p. 5; IP Init. Br., p. 96)

No other party raised any objections to IP's proposal to offer a group balancing service. The Commission finds that this proposal is reasonable should be approved. AmerenIP will be allowed to defer offering this service until the first day of the month in which AmerenIP is migrated to the customer service system used by the other Ameren utilities. In addition, AmerenIP must file the proposed group balancing tariff with the Commission, and post it on the AmerenIP website. at least 45 days prior to its anticipated effective date.

3. Provision of Daily Usage Information and Advanced Metering and Telecommunications Equipment

a. Applicability of Requirement for Equipment – Mandatory versus Optional

In the Tariff Stipulation, Staff and AmerenIP stipulated that advanced metering and communications equipment will be offered on an optional basis to SC 65, SC 66 and Rider OT customers and that AmerenIP can charge an exit fee to customers who elect this service but then terminate it before a specified period of time. (The development of the exit fee is discussed in Section VIII.B.3.c, below.) IP will not be required to provide daily interval usage information to customers that do not elect this optional service. (Tariff Stipulation, par. I.2) In addition, customers electing this optional service (as well as SC 76 customers) will be required to provide a dedicated phone line to the meter at the customer's expense. Other SC 65, SC 66 and Rider OT customers who do not elect this service will be required to provide a non-dedicated commercial phone line. (Tariff Stipulation, par. I.2 and I.4) Specifically, AmerenIP and Staff stipulated to the following language for Section 7(h) of AmerenIP's Standard Terms and Conditions:

7(h) Prior to providing service, Utility shall install electronic metering equipment in each meter through which Customer will be taking service under SC 65, SC 66, SC 76 or Rider OT. If sufficient metering and communications facilities already exist, at Utility's sole discretion, the requirement for installation of additional metering equipment may be waived. At Utility's sole discretion, Utility may require installation of remote interrogation equipment on Customer's electronic metering equipment. All Customers taking service under SC 65, SC 66, SC 76 or Rider OT shall provide access to a 120 volt AC electric power source and to a commercial telephone line for each meter, at Customer's expense. The commercial telephone line provided by those Customers taking service under SC 76 shall be dedicated for Utility's use. The commercial telephone line provided by Customers taking service under SC 65, SC 66 or Rider OT that elect online access to daily usage data shall also be dedicated for Utility's use. (Tariff Stipulation, par. I.5)

No other party raised any objections to these provisions. Accordingly, based on the record, including the Tariff Stipulation, the Commission concludes that they should be approved.

b. Development of Charges for Electronic Metering Equipment and for Advanced Metering and Telecommunications Equipment

AmerenIP witness Althoff provided cost information for the equipment necessary to be installed in order for customers to have access to usage information on a daily basis. There are two components to the charges for this equipment. The first component would recover the cost of the electronic metering equipment necessary to record the customer's daily demands. The second component would recover the cost of the communications equipment needed to allow AmerenIP to remotely access information

contained within the customer's meter. (IP Init. Br., p. 98) As updated based on the final, stipulated cost of capital in this case, the monthly cost for the electronic metering index is \$16.59 and the monthly cost for the communication equipment is \$21.19. The total monthly cost for both is \$37.78. (Tariff Stipulation, App. A) Based on these monthly costs, the stipulated monthly charges are \$16.50 for the electronic metering index and \$21.25 for the communication equipment. (*Id.*, par. 1.3; see IP Ex. 7.30, p. 15) No other party took issue with the proposal for the two separate fees or for the specific charges as set forth in the Tariff Stipulation. Accordingly, AmerenIP should be authorized to implement separate charges for the electronic meter index and for the advanced communications equipment, to be set at \$16.50 per month and \$21.25 per month, respectively.

c. Exit Fee

IP stated that if a SC 65, SC 66 or Rider OT customer chooses to take optional metering and communications service but then later elects to terminate that service, IP will be exposed to non-recovery of the installed costs of this equipment, which could ultimately be recovered from other customers. (IP Ex. 7.30, p. 15; IP Init. Br., p. 98) IP witness Jones explained that to address this problem, either the SC 65, SC 66 and Rider OT customers could pay an upfront fixed fee for the service and forgo the incremental monthly meter communications fee, or the customers could be charged an exit fee if they elect to leave the service within a specified time period following the initial equipment installation date. The amount of the exit fee would be determined by the following formula: Exit Fee equals (Required number of months minus number of previous monthly payments) times monthly fee. (IP Ex. 7.30, p. 16) In the Tariff Stipulation, AmerenIP and Staff stipulated that AmerenIP would be allowed to charge the exit fee to customers that elect the optional electronic metering and communications equipment but then terminate this service in less than six years (72 months). The customer's exit fee will be calculated as follows: Exit Fee equals (72 months minus number of previous monthly payments) times \$21.25. (Tariff Stipulation, par. 1.4)

No other party raised any issue with respect to the proposed Exit Fee or the formula for calculating the Exit Fee. Based on the record, including the Tariff Stipulation, the Commission finds that the proposed Exit Fee, to be applicable to customers that elect the optional daily usage information service but then drop this service less than six years after commencing it, and the formula for calculating the Exit Fee, are reasonable and should be approved.

4. IIEC's Proposed Storage Service

a. IIEC's Position

b. IP's Position

IP responded to IIEC's proposal that IP should be required to offer an optional storage service for transportation customers. IP contended that the IIEC proposal is

deficient in a number of respects and should be rejected by the Commission. While Dr. Rosenberg claimed that the premise for his storage service proposal was the mitigation of potential balancing costs to the SC 76 customers, IP pointed out that it has agreed to many rate design and other changes that will provide additional flexibility regarding balancing for SC 76 customers (and other customers as well). These include implementing a group balancing service and modifying IP's original daily balancing and cashout proposal so as to provide for an initial 20% deadband within which there will be no daily cashout payments. Under the group balancing tariff, the aggregate daily imbalance of all the customers in the group will determine whether the customers are subject to a daily cashout requirement (i.e. whether as a group the customers are within or without the 20% deadband). (See Tr. 230-231) Further, AmerenIP will make available to SC 76 customers daily usage information that will assist customers in remaining in balance. IP also noted that transportation customers already can have access to storage service by taking a firm supply rate and transportation service under Rider OT. (IP Ex. 8.14, p. 9) Additionally, retail customers can obtain storage services from interstate pipelines and third party providers. (Tr. 78) (IP Init. Br., pp. 99-100)

IP argued that IIEC's proposal is clearly results driven. AmerenIP witness Blackburn put forth a hypothetical example that showed how a transportation customer could take advantage of IIEC's proposed storage service if IP were required to offer it. Even though the hypothetical customer would receive basically the same level of service as under IP's proposals, the customer would pay far less (\$4,846 per month as compared to \$3,592 per month) under IIEC's proposal as a result of taking advantage of the IIEC-designed storage service. (See IP Ex. 8.6, pp. 23-24) IP noted that Dr. Rosenberg did not attempt to refute Mr. Blackburn's hypothetical in his own rebuttal testimony. (IP Init. Br., p. 100)

IP stated that the fact that under IIEC's proposal, the customer's Balancing Maximum Quantity (BMQ) would be zero on critical days is a nearly irrelevant consideration insofar as many of the largest SC 76 customers' peak day loads occur during times when critical days are not likely to occur. (IP Ex. 8.6, p. 24) IP also pointed out that although IIEC witness Dr. Rosenberg asserted that his proposed optional storage service is a means to enable transportation customers to mitigate against potential imbalances, under his proposal the customer may nominate injections into the optional storage service; therefore, there would be no mitigation activity. (*Id.*, pp. 24-25) IIEC stated that Dr. Rosenberg's backup plan, under which a customer should be able to inject at least 22% of its BMQ into storage, is also flawed. IP pointed out that in developing this proposal, Dr. Rosenberg employed an incorrect peak day allocator, as he excluded SC 76 and SC 90 volumes. IP also contended that Dr. Rosenberg suggested that "diversity" allows for the 22% BMQ to be inflated to 50%, without any basis in fact. IP stated that IIEC could not claim that on each and every day there will be diversity, or even enough diversity on the system that would allow for this arbitrary adjustment. (IP Ex.8.6, pp. 25-26; IP init. Br., pp. 100-101).

IP concluded that there has been no demonstrated need for the storage service proposed by IEC, and that IIEC's proposal to require an optional storage service to SC 76

customers was ill-considered, poorly developed and poorly supported. Further, IP noted that in case there was any concern that SC 76 customers needed additional flexibility to mitigate potential imbalances under the daily balancing provisions IP originally proposed in this case, those concerns were largely dissipated by IP's agreement to adopt Staff witness Iannello's modifications, including the expanded daily balancing tiers, the 20% deadband, the provision of daily usage information and the implementation of a group balancing service. (IIEC Init. Br., p. 101)

c. Commission Conclusion

Based on its review of the record and the arguments presented by AmerenIP and IIEC, the Commission concludes that IIEC's proposal to require IP to offer a storage service to SC 76 customers should not be adopted. The record shows that the modifications made by IP to its original proposals for balancing and cashout provisions for SC 76 in this proceeding, including the expanded daily balancing deadband in which no daily cashout will be applicable, the ability to net daily imbalances during the month for to eliminate or minimize the monthly cashout, the availability of daily usage information to the customers, and the introduction of a group balancing service, largely mitigate the concerns that might have warranted making a balancing storage service available for SC 76 customers. Additionally, the Commission notes that a banking storage service from IP is available to transportation customers that take IP's Rider OT in combination with a firm tariff. The Commission is also concerned that the scope of IIEC's proposed storage service or the likely subscription to it has not been sufficiently defined in this proceeding so as to enable the Commission to determine the extent to which SC 76 customers might utilize IP storage resources that would otherwise be used to serve firm supply (PGA) customers of IP. In addition, there are concerns remaining in the record about the basis for IIEC's proposed parameters and pricing for the storage service. In other words, in addition to the fact that a need for the storage service has not been shown, the Commission finds that the proposed service has not been adequately developed in the record of this proceeding.

5. Recovery of Transportation Administration Costs

IP's present transportation tariffs, SC 76 and Rider OT, contain an Administrative Charge intended to recover IP's additional administrative costs associated with handling transportation accounts. IP proposed to continue the Administrative Charge for transportation customers in the tariffs approved in this case. (IP Ex. 7.10, pp. 21-22, 22-23) However, Staff witness Iannello proposed that the Administrative Charge for transportation customers be eliminated and that these costs instead be recovered through the Facilities Charges applicable to all customers under SC 63, SC 64, SC 65 and SC 76 (i.e., customers eligible to transport gas). Mr. Iannello's rationale was that imposition of a separate Administrative Charge to transportation customers only could present a disincentive to customers electing to purchase and transport their own gas; and that IP's administrative costs to serve transportation customers are largely fixed and do not increase with the addition of each new transportation customer. (Staff Ex. 8.0, pp. 33-37) IP agreed to Mr. Iannello's proposal. (IP Ex. 7.19, p. 17) Accordingly,

IP eliminated the Administrative Charge from proposed SC 76 and Rider OT, and reset the Facilities Charges in SC 63, SC 64, SC 65 and SC 76 to reflect that the cost associated with administration of transportation tariffs are to be borne by all non-residential customers. (*Id.*)

No other party objected to elimination of the separate Administrative Charge in SC 76 and Rider OT and the recovery of IP's administrative costs associated with transportation service through a general increase to the Facilities Charges applicable to all non-residential customers. Based on the record, the Commission finds that this change, as recommended by Staff and accepted by AmerenIP, is reasonable and should be approved.

6. Critical Day Imbalance Charge

IP proposed a Critical Day Imbalance Charge ("CDIC") for SC 76. Under the original proposal, on a critical day called by IP on which a customer's imbalance differs by more than the greater of 10% of the customer's nomination or 1,000 therms and contributes to imbalance charges imposed on IP (as the Point Operator and balancing agent) by an interstate pipeline (i.e., the customer's imbalance is in the same direction as IP's imbalance on the pipeline), the customer's imbalance would be subject to an additional CDIC. The CDIC would be calculated as the aggregate of pipeline penalties or fees incurred by IP for the critical day divided by the aggregate therms of imbalance created by SC 76 customers and IP that contributed to the penalties and fees. The CDIC would be applied to those transporting customers contributing to the penalties or fees, and would be assessed on the basis of the customer's therms of Critical Day Imbalance, which is that imbalance in excess of the greater of 10% of the customer's nomination and 1,000 therms, that contributed to the pipeline penalties or fees. (IP Ex. 8.1, pp. 8, 9-10)

Staff witness Iannello expressed one concern about the proposed CDIC, namely, that it treated transportation customers individually rather than as a group for purposes of assessing the CDIC. He recommended that, instead, the imbalances of all transportation customers as a group be considered in applying the CDIC, thereby allowing the imbalances of transportation customers in the direction of the pipeline imbalance to be offset by any transportation customer imbalances in the opposite direction. (Staff Ex. 8.0, pp. 31-33) He also noted that where IP calls a critical day for only a portion of its service area, then the subset of SC 76 customers located in the area for which the critical day was declared should be treated as a group for purposes of assessing the CDIC. (Staff Ex. 18.0, p. 13) In the Tariff Stipulation, IP and Staff stipulated to adopt Mr. Iannello's modifications to IP's CDIC proposal. (Tariff Stipulation, par. I.1)

No other party raised any issues with respect to the proposed CDIC, as modified in accordance with Staff's recommendation per the Tariff Stipulation. The Commission finds that the modified CDIC is reasonable and should be approved.

7. Other Changes to Rider OT

In its tariff filing, IP proposed the following changes to Rider OT, Optional Transportation of Customer-Supplied Gas with Firm Utility Gas Supply Backup: (1) eliminate the current practice of cashing out the customer's storage bank balance in October of each year; (2) change the price on which billing period cashouts are based to the Chicago citygate index price; and (3) provide specific intra-gas day nomination rights for Rider OT customers. (IP Ex. 8.1, p. 16) In addition, IP stated that in Rider OT it is formalizing its current practice of allowing customers to nominate only on those pipelines that can provide gas to the customer. This access can change over time due to physical changes on the system, contractual changes with the pipelines and seasonal operational constraints. AmerenIP will be responsible for updating this information and making it available to transporting customers. (*Id.*) There was no objection to any of these changes by any other party. The Commission finds these changes to be reasonable and that they should be approved.

C. Other Changes to Bundled Gas Tariffs (Service Classifications 51, 63, 64 and 65)

In its tariff filing, IP proposed to change the term "Commodity Charge" to "Delivery Charge" in SC 51, SC 63, SC 64 and SC 65. (IP Ex. 8.1, p. 3) There was no objection to this change, and it should be approved. All other issues relating to changes to AmerenIP's bundled gas service tariffs proposed in this case are addressed in other sections of this Order.

D. Other Changes to AmerenIP's Standard Terms and Conditions and Rules, Regulations and Conditions Applying to Gas Service

In addition to the proposed changes to its individual service classifications and riders discussed elsewhere in this brief, IP's proposed tariffs reflect a number of changes in its Standard Terms and Conditions and its Rules, Regulations and Conditions Applying to Gas Service ("Rules"). The proposed gas Standard Terms and Conditions were included in IP Exhibit 8.2 and the proposed gas Rules were included in IP Exhibit 8.3, both sponsored by IP witness Blackburn. The proposed changes to the Standard Terms and Conditions include the following (IP Ex. 8.1, pp. 17-18): (1) consolidation of the provisions regarding resale and redistribution; (2) elimination of the Energy Audit Charge and Arrearage Pilot Program (IP no longer provides energy audits to customers, and the Arrearage Pilot Program expired on April 30, 2000 (IP Ex. 8.1, p. 19)); (3) elimination of the provision requiring a minimum initial required MDQ for non-residential customers; (4) clarification that the absence of a nomination by a transportation customer will be treated as a nomination of zero; (5) removal of common definitions and terms and conditions from the SC 76 and Rider OT tariffs and placement of these common terms and definitions in the Standard Terms and Conditions; and (6) addition of several definitions and minor language changes for consistency with IP's

electric utility Standard Terms and Conditions (for example, Sections 2 (Modification of Schedule of Rates and Contracts), 3 (Terms of Payment) and 4 (Additional Charges)).

With respect to the consolidation of the provisions regarding resale and redistribution, the consolidated provision (Section 1 of the Standard Terms and Conditions) incorporates language from the current Standard Terms and Conditions, Rules and IP's Gas Operating Procedures, and is intended to provide a more complete description of those situations that require separate metering and billing. The proposed provision does not represent a change from IP's current practices. Generally, unless heat or hot water is provided to tenants of a building through a common system without incremental charges for such service, or unless units meet certain other criteria detailed in this tariff section, separate metering and billing is required. (IP Ex.8.1, p. 18)

IP stated that the provision requiring a minimum required initial MDQ is being eliminated in order to allow the customer to establish its initial MDQ at a level that reflects the customer's expected operations rather than past operations. IP stated that the excess MDQ charges in its tariffs provide sufficient incentive for customers to set their MDQs at appropriate levels. (IP Ex. 8.1, p. 19)

The proposed changes to IP's gas Rules include the following (IP Ex. 8.1, pp. 19-20): (1) removal of definition from the Rules and placement of the definitions into the Standard Terms and Conditions, so that definitions are found in one place; (2) removal of provisions concerning resale and redistribution and consolidation of provisions on this topic into the Standard Terms and Conditions, as discussed above; (3) clarification of IP's right to relocate gas facilities at the customer's expense if the customer's premises, operations or gas utilization are dangerous; (4) clarification that customers will bear the cost of changes in gas facilities that they initiate regardless of potential revenue impacts; (5) clarification that base rate revenue is the basis for the revenue allowance calculation for determining the length of free gas main extensions; (6) clarification as to what constitutes dangerous conditions that would allow IP to deny or terminate service; (7) clarification that additional costs incurred in disconnecting or reconnecting service other than at the meter may be borne by the customer; and (8) minor language changes to improve clarity.

With respect to the clarifications in the gas Rules that a customer bears the cost of relocating facilities due to an unsafe condition if the customer is responsible for the unsafe condition, that customers are responsible for the costs of changes to facilities that they initiate, and that a customer may bear the additional costs incurred by IP in disconnecting or reconnecting service other than at the meter, IP stated that these provisions are intended to follow the principle that a customer that causes such costs should be responsible for paying those costs instead of the costs being spread across all customers. (IP Ex. 8.1, p. 20) With respect to the clarification that the customer's base rate revenue is the basis for the revenue allowance for determining the length of the free gas main extension provided to the customer, IP stated that it receives no profit from gas sales, only dollar-for-dollar cost recovery; therefore, it would be inappropriate

to incorporate the cost of gas consumed by the customer into the revenue allowance for determining the length of the free gas main extension. (*Id.*, pp. 20-21)

Other than the tariff provisions that are specifically discussed elsewhere in this Order, no party took issue with any of the proposed changes to IP's Standard Terms and Conditions or to its Rules. Accordingly, the Commission concludes that IP's proposed Standard Terms and Conditions and gas Rules (except to the extent modified during the course of this case as provided elsewhere in this Order) are reasonable and should be approved.

E. Treatment of Past-Due Payments

1. CNE-Gas Position

2. IP's Position

IP responded to the testimony of CNE-Gas witness Claussen that IP should elect the option of treating a payment as past due if the payment is postmarked after the due date printed on the bill. IP did not accept this proposal. IP stated that as permitted by 83 Ill. Admin. Code 280.90(a), it treats a customer payment as past due if the payment is received more than two days after the due date printed on the customer's bill. IP pointed out that Code Part 280.90(a) identifies the two options referred to by Ms. Claussen by which a utility may determine if payments are past due, and Code Part 280.90(b) states, "Each utility shall choose one of the above methods for determining when a bill is past due and shall apply this method to all customers." IP has elected to use the method that requires mailed payments to be received by IP within two days following the due date in order to be considered on time (not past due). IP stated that Code Part 280.90(b) allows IP to elect to use this option, and does not authorize the Commission to direct a utility to use the other option. IP stated that to change to the "postmark" method for all customers, as it would be required to do by Part 280.90(b), would result in significant added administrative expense and costs for changes and reprogramming to IP's billing systems. Additionally, IP stated that the "postmark" method would be less cost-effective, because IP would have to document and/or store the postmarks on hundreds of thousands of envelopes sent to IP each month. Finally, use of the "postmark" method would likely extend the date on which many customers send payments to IP, thereby slowing IP's cash flow and increasing its cash working capital requirements, which would increase the revenue requirement and be paid for by all customers. (IP Ex. 8.6, p. 10; IP Init. Br., pp. 107-08)

IP stated that customers who are concerned about possible mail delays in the receipt of their payments by IP can avoid this risk by using other payment options. Any IP customer may elect to pay bills via an electronic funds transfer, to pay electronically via the internet, to pay from a financial account or by credit card over the phone, or to pay in person at a payment center. (IP Ex. 8.6, p. 11) These options allow the customer to pay the bill on the due date without payment being past due.

IP also opposed Ms. Claussen's proposal that the late charge should be prorated based on the number of days (out of 30 in the month) that the payment is received past the due date. When a payment is past due, IP assesses a 1.5% late payment charge on the past due amount. IP stated that, among other things, use of the approach Ms. Claussen suggested would reduce the revenue IP receives from forfeited discounts. Since forfeited discount revenues are included in miscellaneous revenues that are deducted from the overall revenue requirement to determine the net revenue requirement that must be recovered from customers through base rate charges, Ms. Claussen's proposed approach would require an increase in base gas rates. (IP Ex. 8.6, pp. 11-12) Further, IP stated that its practice with respect to application of the 1.5% late payment charge is the same as the practices of all the other major Illinois electric and gas utilities including Commonwealth Edison, AmerenCIPS, AmerenCILCO, Peoples Energy and Nicor Gas. (*Id.*, p. 11)

3. Commission Conclusion

The Commission notes that CNE-Gas did not file any rebuttal testimony to IP on these issues and did not file an initial brief in this case in which it continued to raise these proposals. Further, the Commission agrees with IP that under Code Part 280.90(b), the Commission cannot require IP to make a different election as to which method to use for all customers to determine when a payment is past due. In any event, the record supports IP's position on the issues raised by CNE-Gas.

F. Lost and Unaccounted for Factor

1. IIEC's Position

2. IP's Position

IP responded to IIEC witness Mallinckrodt's concerns with respect to the 2004 value of Factor U, P's unaccounted for gas adjustment charge. IP noted that Mr. Mallinckrodt offered no empirical evidence as to why Factor U was in his view too high or too low, or why any averaging was appropriate given the nature of the charge. IP stated that the Factor U charge is a pass through on which IP makes no profit. (IP Ex. 8.6, p. 19) IP pointed out that in any event, it calculated the new annual Factor U charge to be effective beginning January 1, 2005, and it will be 1.711%, which is lower than what it was for 2004, and even lower than the 3-year averaging proposal suggested by Mr. Mallinckrodt. IP noted that IIEC witness Mallinckrodt agreed to accept IP's Factor U for 2005. (IIEC Ex. 1.1, p. 8; IP Init. Br., pp. 109-110)

IP opposed Mr. Mallinckrodt's suggestion that a procedure should be put in place in the future to review the Factor U proposed each year. IP pointed out that the historical loss factors are provided to the Staff each year as part of a utility's PGA reconciliation case. IP stated that there is no need for a specific, separate procedure to review Factor U each year. (IP Ex. 8.14, p. 9) IP noted that Staff also testified that IP

should not make any changes in the way it calculates its Factor U. (Staff Ex. 17.0R, p. 4; IP Init. Br., p. 110)

3. Staff's Position

4. Commission Conclusion

Based on the record, the Commission concludes that there is no need to require any change in the manner in which AmerenIP determines the annual Lost and Unaccounted For factor (Factor U) or in the procedures by which the Commission reviews the lost-and-unaccounted for experience of the gas utilities each year. A need to move to a three-year averaging process has not been demonstrated.

G. Definition of "Therm"

1. IIEC's Position

2. IP's Position

IP responded to the testimony of IIEC witness Mallinckrodt that IP's gas accounting and billing should be done on a heat content basis rather than on a volumetric basis. IP agreed with Mr. Mallinckrodt that there was a mismatch between the Chicago citygate index price (which is stated on an MMBtu (heat content) basis) that is to be used for cashout purposes and the volumes delivered to IP customers, which are measured on a volumetric basis. In order to address this inconsistency, IP agreed to convert the Chicago citygate price to a volumetric basis for cashout purposes. The conversion will be based on the Btu content of gas delivered to AmerenIP's city gate by NGPL. (IP Ex. 8.6, p. 20) IP noted that Mr. Mallinckrodt indicated acceptance of this change. (IIEC Ex. 1.1, p. 8) However, IP opposed Mr. Mallinckrodt's proposal that AmerenIP should change its gas accounting system to bill and handle gas on a Btu basis. IP witness Blackburn pointed out that both AmerenCIPS and AmerenCILCO utilize a volumetric measurement basis for the therm. (IP Ex. 8.6, pp. 19-20) He also explained that the volumetric measure is used for retail customer billing because most meters at customer premises measure only volumes, not heat content. (Tr. 85) (IP Init. Br., p. 111)

3. Commission Conclusion

The Commission finds AmerenIP's proposed change to convert the Chicago city gate price to a volumetric basis for cashout purposes is a reasonable response to IIEC's specific concern and should be approved. However, the Commission does not find that there is a need at this time to develop a plan for converting AmerenIP's gas billing and accounting systems to a heat content basis. Accordingly, IIEC's additional recommendation that IP be ordered to submit a report and plan for converting its gas billing and accounting systems to a heat content basis is not adopted.

IX. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record and being fully advised in the premises, is of the opinion and finds that:

- (1) Illinois Power Company is an Illinois corporation engaged in the transmission, distribution, transportation and sale of natural gas to customers at retail in this State, and as such is a public utility within the meaning of the Public Utilities Act;
- (2) the Commission has jurisdiction over IP and the subject matter herein;
- (3) the recitals of facts and conclusions reached in the prefatory portion of this Order are supported by the evidence of record and are hereby adopted as findings of fact; the attached Appendix provides supporting calculations for various portions of this Order;
- (4) the test year for the determination of the delivery services rates approved herein is the historic test year ended December 31, 2003; such test year is appropriate for purposes of this proceeding;
- (5) for purposes of this proceeding, Illinois Power's net original cost gas utility rate base is \$497,883,000;
- (6) Illinois Power's proposed revised gas depreciation rates applicable to gas utility plant in service, as described in IP Exhibit 11.3 submitted in this proceeding and as set forth in Section IV of this Order, are reasonable and should be approved pursuant to Section 5-104(a) of the Public Utilities Act;
- (7) a just and reasonable rate of return which Illinois Power should be allowed to earn on its gas utility rate base is 8.18%, which incorporates a rate of return on common equity of 10.00%;
- (8) for purposes of this proceeding, Illinois Power's gas utility revenue requirement, excluding the cost of natural gas and add-on taxes and charges, is \$141,457,000; IP should be authorized to file and place into effect gas utility tariffs which will recover this revenue requirement, net of miscellaneous revenues, through base rate charges, resulting in an increase in annual revenues from base rates of \$14,227,000, based on test year 2003 weather-normalized billing determinants;
- (9) Illinois Power's rates which are presently in effect for gas service are insufficient to generate the operating income necessary to permit IP the opportunity to earn a fair and reasonable return on net original cost rate

base; except as provided in Finding (14), these rates should be permanently cancelled and annulled;

- (10) the rates proposed by Illinois Power in the Filed Rate Schedule Sheets for its gas operations will produce a rate of return in excess of a return that is fair and reasonable; IP's Filed Rate Schedule Sheets should be permanently cancelled and annulled;
- (11) Illinois Power's Service Classifications 51, 63, 64, 65, 66, 76 and Rider OT and the proposed revisions to its Standard Terms and Conditions and to its Rules, Regulations and Conditions Applying to Gas Service, as modified by agreement during the course of this proceeding or as further directed in the prefatory portion of this Order, are hereby found to be just and reasonable;
- (12) the interclass revenue allocation and rate design discussed and accepted in the prefatory portion of this Order are just and reasonable for purposes of this proceeding and should be adopted;
- (13) except as provided in Finding (14), Illinois Power shall file tariff sheets in compliance with the findings and conclusions of this Order containing an effective date not less than three days after the date of filing, with the tariff sheets to be corrected within that time period if necessary; such tariff sheets shall be applicable to service rendered on and after their effective date;
- (14) as discussed in the prefatory portion of this Order, Illinois Power shall file, at least 45 days before its proposed effective date, a tariff to implement a group balancing service; IP's proposed Service Classification 66 and its proposed balancing and cashout provisions for transportation service, as approved in this Order, shall go into effect on the same date as the group balancing service; until such date, present Service Classifications 67 and 68 and the balancing and cashout provisions currently in IP's transportation tariffs shall remain in effect; and
- (15) all objections, petitions or motions in this proceeding which remain undisposed of should be disposed of in a manner consistent with the ultimate conclusions in this Order.

IT IS THEREFORE ORDERED, except as provided in Finding (14) of this Order, that the tariffs presently in effect for gas service rendered by Illinois Power Company are hereby permanently cancelled and annulled at such time as the new gas tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the Filed Rate Schedule Sheets proposing a general increase in gas rates, filed by Illinois Power on June 25, 2004, are permanently cancelled and annulled.

IT IS FURTHER ORDERED that Illinois Power Company is hereby authorized and directed to file new gas utility tariff sheets in accordance with Findings (8), (11), (12), (13) and (14) of this Order, applicable to gas service furnished on and after the effective date of said gas utility tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company's proposed depreciation rates for its gas utility, as described in IP Exhibit 11.3 submitted in this proceeding and as set forth in Section IV of this Order, are hereby approved pursuant to Section 5-104(a) of the Public Utilities Act.

IT IS FURTHER ORDERED that any objections, petitions or motions in this proceeding which remain undisposed of are hereby disposed of in a manner consistent with the ultimate conclusions herein contained.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code Section 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this ___ day of May, 2005.

(SIGNED) EDWARD C. HURLEY

Chairman